MONTANA COAL MARKET TO THE YEAR 2000: IMPACT OF SEVERANCE TAX, AIR POLLUTION CONTROL AND RECLAMATION COSTS

by

Professor John Duffield
Department of Economics
University of Montana

Professor Arnold Silverman
Department of Geology
University of Montana

John Tubbs
Department of Economics
University of Montana

Prepared for the
Montana Department of Commerce
Helena, Montana

January, 1985

List of Figures

TABLE OF CONTENTS

List of Tables

Executive Summary

Conclusions

The major conclusions of this study are as follows:

1. The Montana coal market through the 1971-1985 period has been relatively stable due to locational advantage in Minnesota, Wisconsin, Michigan and by wire to the Pacific Northwest (PNW).

2. The very large relative growth in Wyoming is due to three factors: a) locational advantage to a much larger market including south-central oil and gas states, b) major shifts from oil and gas generation to coal due to rising world oil prices, and c) the expansion of the low sulfur coal market under the New Source Performance Standards for sulfur dioxide emissions in 1971.

3. The cost differentials related to locational advantage (transportation) and air pollution regulations (scrubbers) are on the order of \$5 to \$15/ton. Cost differentials due to Montana and Wyoming coal severance taxes, which are more on the order of \$1/ton, have had an insignificant market impact.

4. In all likelihood, most existing contracts with Montana producers that will expire in the mid-1990's will be renewed even in the absence of severance tax reductions.

5. Based on industry sources and known new contracts, the Montana coal industry is in for steady 3% to 4% annual growth out to 1988, reaching 42 million tons per year (mtpy).

6. The long term forecast for Montana coal production is for substantial growth to between 48 and 85 mtpy in the year 2000, depending on the growth rate of electrical consumption in the market area.

7. Reclamation policies and potential acid rain legislation are unlikely to significantly impact Montana production during the next 15 years.

8. The impact of a $1 price reduction on Montana coal production is slight--around 1.5 mtpy increase in 1990 and 1995 and 6 mtpy in the year 2000, at a 2% electrical growth rate.

9. Severance tax reductions will in no case generate sufficient increased production to offset tax revenue losses on new production that will occur.

10. Revenue losses of a 50% reduction ($1.50) in severance tax for <u>new</u> production will rise from $10 million per year in 1990 to $34 million per year in 2000. The same reduction on the production of <u>all</u> coal will amount to a loss for the state of $58 million per year in 1990 and $83 million per year in 2000.

11. The net present value of lost tax revenues to the year 2000 on a 50% tax reduction on <u>new</u> production only is $105 to $205 million, depending on growth in electrical sales. The net loss on <u>all</u> production of a 50% reduction in tax is $685 to $785 million to the year 2000.

In the following, the analysis underlying these basic conclusions is briefly summarized. The interested reader seeking greater detail is referred to the full report and an earlier analysis completed in 1982 for the Office of Surface Mining, entitled "Projections of Coal Demand from the Northern Great Plains through the Year 2010."

Introduction

This paper provides an economic analysis of the market for Montana and Wyoming coal. The basic purpose of the study is to provide a Montana coal production forecast to the year 2000 and show the sensitivity of this forecast to three policies: The coal severance tax, acid rain legislation, and reclamation policies. The focus is entirely on the derived demand by coal-fired plants in the electric utility sector. This category of use currently accounts for about 95% of Northern Great Plains production. As developed in some detail elsewhere (Duffield et al, 1982), the other current and potential users: (industrial, synfuels, and export) are unlikely to be significant before the turn of the century.

For purposes of our analysis, the electric utility market for coal can be divided into three categories: existing contracts, new plants, and "acid rain" plants. These categories correspond to three different vintages of coal-fired generating units. Existing contracts are mostly for plants that came on line from around 1968 to the present, new plants are those coming on line in the future, and "acid rain" plants are older plants built under lenient sulfur emission regulations. Our basic conclusions for each market will be summarized in turn.

Existing Plants and Contracts

The dominant factor explaining the pattern of current contracts for Montana and Wyoming coal is location. For example, given the existing rail network, Colstrip area coal has a 240 mile edge over Wyoming Powder River for shipments east to Minneapolis. However, to the south (Texas, Oklahoma, etc.) Gillette area coals have a 330 mile advantage. At the current average rate for coal unit trains of .017 \$/ton-mile, the respective advantages are \$4.08/ton to Montana in some north-central markets and \$5.61/ton advantage to

Wyoming to the south. This difference is very important and has the same impact on delivered price as an equivalent difference in FOB mine price. Because of these very important locational differences vis-a-vis markets and existing rail routes, there are well defined spatial markets for Montana and Wyoming coals.

Between 1971 and 1985, 176 major new coal-fired plants were built in the 19 state coal market in which Wyoming and Montana compete. In this period there were only six states where new plants were burning Montana coal as they came on line: Montana, Minnesota, Wisconsin, Illinois, Michigan and Texas. (The deliveries to Texas were for Decker and Spring Creek coals, which are located only 125 miles north of Gillette, and can compete on some longer rail hauls due to their higher BTU content.) Market shares in the 19 state area for three specific time periods 1971-1975, 1976-1980, and 1981-1985 are summarized in Table S-1. As can be noted, the Montana market share has been relatively stable at around 10%, while the Wyoming share jumped dramatically from 16% to 53% between 1971-75 and 1976-80.

As developed in some detail in the report, the change in the Wyoming market is mainly due to the dramatic increase in oil and gas prices following the Arab oil embargo of 1973-74. Prior to that time almost all electric generation in the large south-central market of Arkansas, Louisiana, Oklahoma, Nebraska, and Texas was by oil and gas. Between 1971-1975 there were only four new coal-fired plants brought on-line in this area (all in Texas) and none used Wyoming coal. However, between 1976 and 1985, 51 coal-fired plants were built and 41 of these burned Wyoming coal, accounting for increased Wyoming prodution of about 66 million tons per year. By contrast, Montana picked up only a share of several new Texas plants in the south-central area in this period or about 4 million tons per year.

Table S-1

Market Share Summary
for New Coal-Fired Plants
in the 19 State Market Area*

Coal Source	Time Period: On Line Date			
	71-75	76-80	81-85	Total
Montana				
# of plants	5	9	6	20
mw capacity	1744	3589	2929	8262
share of mw	.080	.095	.107	.095
Wyoming				
# of plants	10	38	35	83
mw capacity	3392	19785	17121	40298
share of mw	.156	.526	.623	.464
Other				
# of plants	31	25	16	73
mw capacity	16664	14255	7420	38339
share of mw	.764	.379	.270	.441
Total				
# of plants	46	73	57	176
mw capacity	21800	37629	27470	86899

* AR, CO, IL, IA, IN, KS, LA, MI, MN, MO, MT, NB, ND, OK, OR, SD, TX, WS, and WY

The other major market factor in 1971-1985 was the adoption of federal New Source Performance Standards (NSPS) limiting sulfur dioxide (SO_2) emissions from coal-fired plants to 1.2 lbs. of SO_2 per million BTU's. These standards were applied to plants which began construction after September 1971. Given a construction time lag of five to eight years, these standards impact coal source choices after 1976. Most Gillette area and Montana Decker and Spring Creek coals are well below .6% sulfur by weight and high enough in BTU value that they can meet NSPS without scrubbing. However, Colstrip area coals are around .7% to .8% sulfur and require costly scrubbing to meet NSPS. As a result, for example, new plants on line in Wisconsin after 1976 have used Wyoming coal even though Montana has a lower delivered price due to locational advantage.

In 1978, sulfur regulations were revised to require scrubbing on all coals. The cost of scrubbing low sulfur western coals is around $5.00 to $8.00/ton (1980 dollars) and $15/ton for 3.4% sulfur Illinois coal. These Revised New Source Performance Standards (RNSPS) mean that states on the fringe of both the Montana and Wyoming markets (Illinois, Texas, Louisiana, Arkansas, etc.) will be less likely to buy NGP coal than in the past. On the other hand, most of the relative disadvantage to slightly higher sulfur Colstrip area coals disappears under RNSPS.

Locational advantage and changes in sulfur emission regulations account for cost differences on the order of $5 to $15 per ton. By contrast the effective coal severance tax rates (as a % of selling price) for Montana and Wyoming are 21% and 11% respectively. On typical $10 to $11/ton coal this amounts to only about a dollar a ton difference. For typical delivered prices of $25 to $40 per ton (with transportation accounting for $15 to $25 of the cost), coal severance tax differences are relatively small--2% to 4% of

delivered price. Needless to say, very small differences in the transportation rate (for example, only 1 mill per ton-mile differences over 1000 miles) have an equivalent effect.

Changes in the Montana coal market share by state for new plants in the 1971-1985 period were analyzed. There were no cases identified where the small difference between Montana and Wyoming coal severance taxes were a significant factor in determining the least cost choice of the utility purchasing the coal.

The major conclusions from this analysis of market share for existing plants are as follows. The Montana coal market share through the 1971-1985 period has been small but relatively stable due to the locational advantage in Minnesota, Wisconsin, Michigan and by wire to the PNW. The very large relative growth in Wyoming is due to three factors: 1) locational advantage to a much larger market including the south-central oil and gas states, 2) major shifts from oil and gas generation to coal due to rising world oil prices, and 3) the expansion of the low sulfur coal market under the NSPS of 1971. As developed in some detail in our main report only the Decker and Spring Creek coals in Montana benefited significantly in this period from the NSPS.

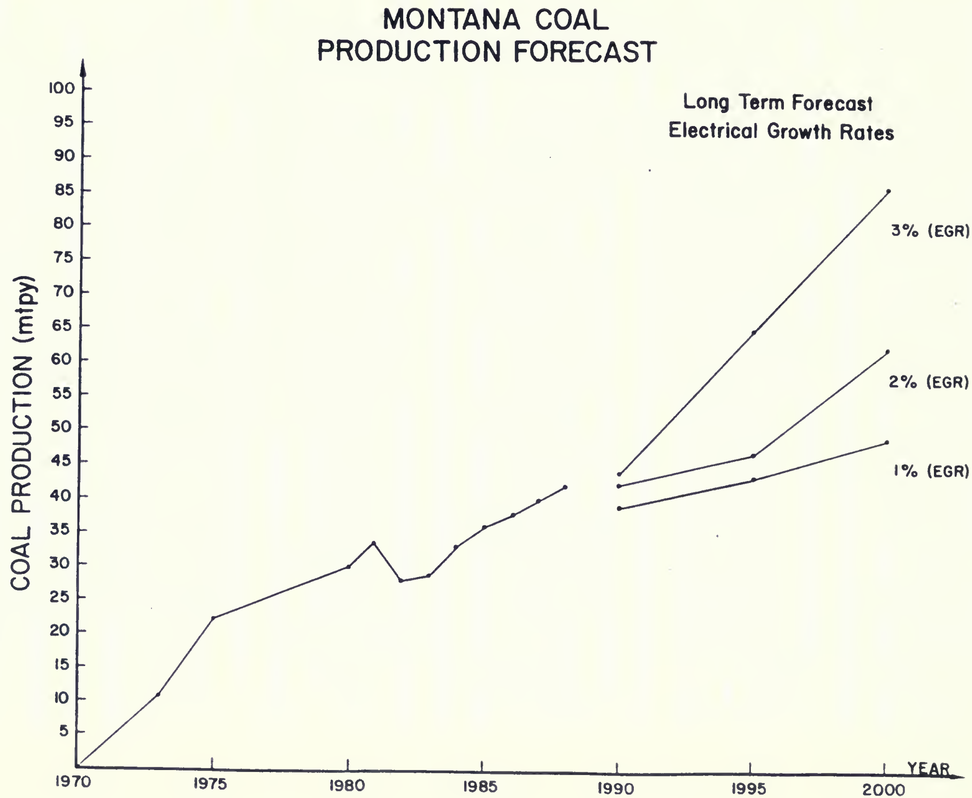
Our forecast for production related to existing contracts is for no major changes to the year 2000. About 12 million tons of current production is tied to contracts that are up for renewal in 1993-1995. Almost all of this coal is for burn sites in Minnesota and Wisconsin. Our analysis indicates that most of these sites continue to be in the Montana market for the most probable set of new bid prices. In the late 1990's, some Decker and Spring Creek contracts begin to expire in Illinois, Texas, and Michigan. These have not been closely analyzed given the proximity of the expiration date to the last year of our forecast, and the uncertainty concerning new bid levels from Decker.

New Plants--Near Term

Our forecast for Montana coal production is summarized in Figure S-1. As it is assumed that the greater part of existing contracts will be renewed, the increases we project are based on the steam coal market due to new plants on line after 1984. The near term forecast (to 1988) is based on a survey of Montana mines undertaken by the Montana Governor's office. Montana mines expect production to increase from 32.3 mtpy (estimate) in 1984 to 41.6 in 1988. Much of this growth is due to contracts for a new plant in Michigan (Belle River #2) and Colstrip 3 and 4. It appears, based on industry sources, that the Montana coal industry is in for a period of steady growth (3% to 4% annually) for the next few years.

The near term forecast can be extended to 1993 based on utility ten year plans as summarized by the National Electric Reliability Council (NERC). In the historical Montana market described above there are only two plants without coal contract commitments that will be coming on line to 1993, Northern States Power (NSP) Sherco #3 in 1988 near Minneapolis and NSP's Wisconsin Coal #1 in 1993. These units combined would contract for about 4 million tons of coal. Even very major extensions of the Montana market due to substantial price reduction could at most add to this another 7 million tons of potential new plant market by 1993 in Iowa, Missouri, Nebraska and Indiana. There is no new uncontracted coal-fired capacity to come on line to 1993 in Montana, Michigan, the Dakotas, Nebraska, Kansas, Oregon, Illinois, or Wyoming. This new production range of 4 to 11 new mtpy by 1993 is an upper limit since it is predicated on the current NERC "sum of utilities" forecast for our market of around 2.5% electric sales growth per year. This is down considerably from even last year's NERC forecast of around 3.2%.

Figure S-1


MONTANA COAL
PRODUCTION FORECAST
Long Term Forecast
Electrical Growth Rates
3% (EGR)
2% (EGR)
1% (EGR)
COAL PRODUCTION (mtpy)
100
95
90
85
80
75
70
65
60
55
50
45
40
35
30
25
20
15
10
5
1970
1975
1980
1985
1990
1995
2000
YEAR

Sherco #3

Because it is possible that the only new plant on line in our market to 1993 is NSP's Sherco #3, we have closely analyzed the relative cost of Wyoming and Montana coals at this burn site. We have used costs estimated from delivered prices at NSP plants in the Minneapolis area. NSP is currently taking deliveries on the first Wyoming coal contracts ever in Minnesota (historically Montana's market). This coal is from a new mine, the Rochelle, with relatively high BTU content (8900) and a mine mouth price of only $6.00 a ton. On a delivered price basis, this coal is about $1.11/ton (or 8.3¢/MMBTU) cheaper in Minneapolis than Colstrip deliveries under old contracts at around $11.00 a ton. This is in part due to the new rail extension into the southern Powder River by Chicago Northwestern and Union Pacific, which are apparently underbidding Burlington Northern by about 1 mill per ton-mile--good for around $1.00/ton on 1,000 mile deliveries. In general both Wyoming and Montana new bid prices (for 8400 to 8700 BTU coal), estimated to average $7.70/ton and $9.50/ton respectively, are below the current average prices for existing contracts of $9.77/ton Wyoming and $11.00/ton for Montana. In short, market conditions are leading to price reductions, which, in some cases, are quite substantial.

When we compare potential new bids at Sherco #3, taking a low Wyoming bid ($6.00 on 8900 BTU coal) and an average Montana bid ($9.50 on 8700 BTU coal), we show Montana with a $1.08 a ton advantage, or about 6.2¢/MMBTU. Since CNW does not deliver directly at the Sherco #3 site, we have assumed equal rail rates. A more typical Wyoming bid, at $7.70 and 8450 BTU would make the advantage to Montana even greater, at about $2.80 per ton.

There are three "wild cards" here: the FOB bid prices, uncertainty over rail rates, and the basis for the NSP decision. On the Wyoming FOB, a bid

lower than $6.00 for 8900 BTU coal seems doubtful. On the Montana FOB, it is unclear why to date Montana producers have not matched Wyoming price reductions. An analysis of production costs was initially proposed for this study, but not funded, and is beyond the scope of our current investigations. Conservatively assuming that Montana producers can go to at least $9.50 FOB, it is likely this would be the low bid for delivered coal at Sherco #3.

Rail rates are the fastest rising part of the price puzzle for electricity. As long as they do not rise differentially between carriers of Montana and Wyoming coal, we should be competitive in markets where rail distance, BTU content and sulfur content make Montana coals the least cost choice.

The third "wild card" is the basis of the NSP decision. It has been asserted that at least at some utilities there is a "subjective bias" against Montana coal because of our severance tax and "antibusiness attitude." It appears to us that utilities have to pay close attention to even rather small differences in price. For example the estimated $1.08/ton or 6.2¢/MMBTU difference at Sherco #3 for Montana coal amounts to about $2 million per year or $60 million over the plant life on fuel costs alone. Our conclusion here is that for typical new bid prices and similar rail costs, Montana will continue to dominate the Minnesota market. Even taking a very low Wyoming bid and an average Montana price, we show a continued locational advantage to Montana producers.

New Plants--Long Term

Our long term forecast for Montana coal production is also shown in Figure S-1. The key uncertainty here has to do with the growth rate of electrical consumption in our market area. We illustrate the difference between 1%, 2%, and 3% electric sales growth scenarios. In the year 2000, the "3%" forecast results in 85.4 mtpy, or almost double the 1% case at 48.3 mtpy. The

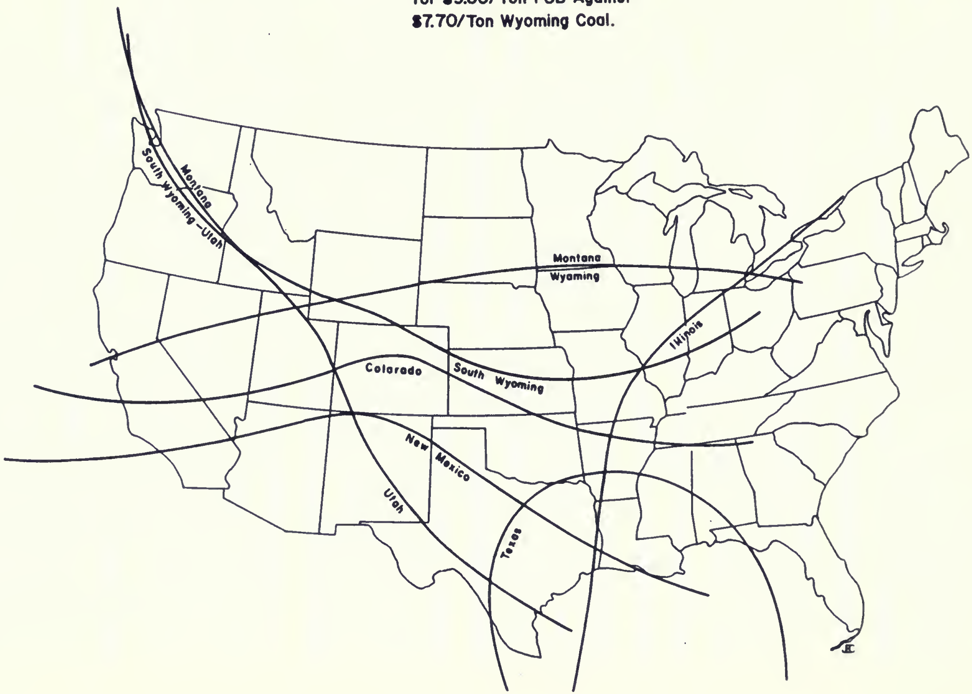
sophisticated forecasting models being applied to the Pacific Northwest by the Northwest Power Planning Council (NPPC) and Bonneville Power Administration (BPA) are predicting growth at around 1.5% to the year 2000, with zero probability of growth greater than 3%. On the other hand utilities in the midwest are building to meet growth no greater than around 2.5%. On this basis, we have chosen 2% as our base case, and performed sensitivity analysis on our major results at both 1% and 3%.

Our long term forecasting model has three key components: a spatial market model, electric growth forecast, and an interfuel substitution algorithm. In our spatial market model we identify the geographical area where Montana coal is least cost against seven competing coal supply centers including Texas, Wyoming, Utah, and Illinois. As detailed in the report, we incude all costs associated with burning a specific coal, including air pollution control costs (scrubbers), boiler size due to BTU content, transportation, etc. Costs are on a present value basis over the life of a prototype 500 mw generating unit, and include fuel and transportation escalation assumptions.

The results of a typical computer run of the model is the spatial map illustrated in Figure S-2. The results indicate that at $9.50/ton Montana versus $7.70 per ton Wyoming, the Montana market includes most of Minnesota, Wisconsin, Michigan, Washington, Montana, and northern Idaho. Because the model is based on the assumption that a coal supply center is a single point, the Montana market is overstated to the extent that there are many potential mine locations within a given coal production region. For example, we have ignored Central Basin coals in Iowa and Missouri, and in Wyoming the supply center we use is to the south of Gillette at Bridger Junction. Because of extensive coal deposits throughout Wyoming and North Dakota, the latter are excluded from the

Figure S-2

Montana Coal Market Area
for $9.50/Ton FOB Against
$7.70/Ton Wyoming Coal.



Montana market in all cases. Mine mouth generation using North Dakota lignites has historically served electric growth in both the Dakotas.

Once a spatial market is identified, the total electric generation in that market is estimated. Known projected and existing nuclear, hydro, oil and gas, and exisiting coal generation is then subtracted on a state level to estimate residual (new coal) generation.

Using this model we have identified the spatial market (and coal tonnages) associated with alternative prices of Montana coal: \$10.50, \$9.50, \$8.50, \$7.50, and \$6.50. Comparison of the results at \$10.50 and \$9.50, for example, provides a basis for predicting the new coal production associated with a \$1.00 price cut (due to severance tax change, etc.). Because of uncertainties in Wyoming prices, we ran the model for both a \$7.70 and \$6.00 Wyoming case. The results for our base case are summarized in Table S-2. A major finding is that because of Montana's locational advantage in the north-central region and PNW, there is likely to be steady and substantial growth in coal production even without price reduction. The second major finding is that the incremental production associated with a given \$1.00 price reduction is small, averaging around 1.5 mtpy in 1990 and 1995 and 6 mtpy in the year 2000 against the base prices, all for 2% growth.

As developed in considerable detail in the main report, price reductions in every case expand our market. However, in many cases, the new areas where we become competitive have no potential new coal generation to the year 2000. For example, Illinois has a very large amount of nuclear capacity (about 8000 mw) coming on in the next few years and shows no need for new coal in even a 3% growth scenario. Similarly, in the Pacific Northwest we have relied on the NWPPC's forecast of loads and resources. Only in the "high" case (3% growth) is there any need for new coal in the Northwest, and then only in the year

Table S-2

SUMMARY

Base Case Montana Coal Production Forecast
(million tons per year)

Year:	1990			1995			2000		
Electric Growth Rate:	1%	2%	3%	1%	2%	3%	1%	2%	3%
Total Production	38	42	43	42	46	65	48	63	85
New Production	6	9	11	10	14	32	16	31	53
[a]Increase for $1/ton Price Reduction	.9	1.5	1.3	1.6	1.2	6.9	1.0	5.7	13.5

Note: [a]Increase is based on average of 9.50 and 10.50 Montana FOB and 6.00, 7.70 Wyoming FOB cases.

2000. This is due in part to the conservation, hydro, and combustion turbine resources expected in the Northwest.

Acid Rain Plants

Another potential market for Montana coal is the set of older plants, mainly in the midwestern states, that currently burn high sulfur fuels. Because of the increased scientific evidence that links coal-fired electric generating plant emissions of SO_2 with acid precipitation impacts, a number of bills were proposed in the last Congress to reduce SO_2 emissions by 8 to 12 mtpy. The bills are of two major types. The Sikorsky/Waxman Bill (HR3400) for example, would require scrubbers on the "top 50" emitters and leave a potential of 30 to 50 mtpy of high sulfur coal use that could be switched to low sulfur. The other type of bill, typified by S2001, the Durenburger Bill, would have no explicit technology forcing provisions. Utilities would be free to choose the least cost mix of scrubbing and switching on their system. At present there is a great deal of uncertainty over the target level of reduction and the means of achieving that reduction.

While the potential "acid rain" market for the NGP may be anywhere from 37 to 117 mtpy, the actual share will depend critically on the type of legislation (scrub or switch) and on the unit-specific economics. Many of the older plants designed for bituminous coals may not be able to burn the low BTU, high ash, high sodium western coals or only at a large expense. An analysis has been undertaken by ICF that takes into account the match of unit and coal source characteristics and assumes that utilities will minimize costs. The ICF report estimated that by 1990, acid rain legislation would add only 10 mtpy to the NGP market. Based on historical market shares, this would imply perhaps 2.5 mtpy for Montana. In short, even under the most optimistic scenario (there is an

acid rain bill and it allows utilities to scrub <u>or</u> switch), the Montana market for acid rain plants is anywhere from 0 to 3 mtpy.

In fact, given the current mood of the National Congress, the pull-back of legislative leaders who championed acid rain reduction in the last Congress, and the Presidential (E.P.A.) assessment of new study requirements, it appears unlikely that acid rain reduction will be mandated by the Congress in this decade.

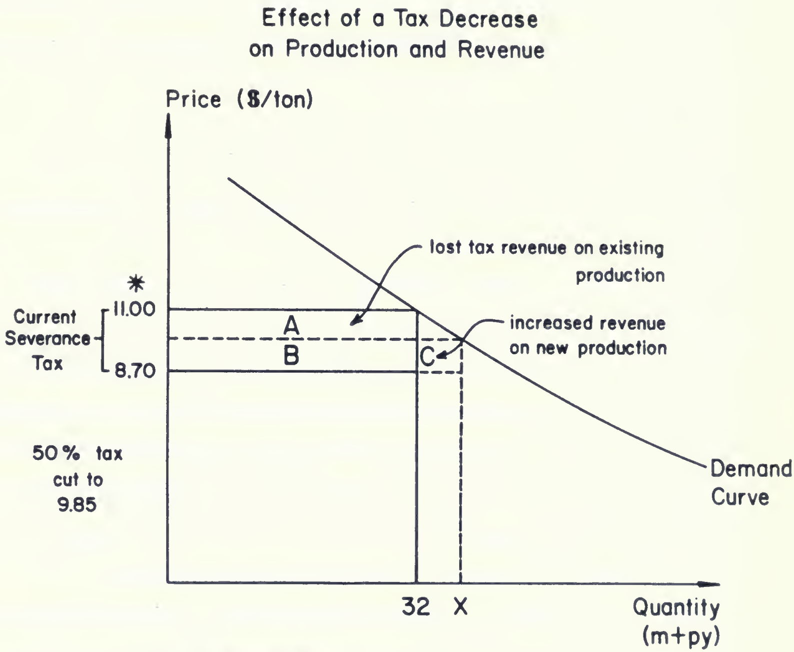
Policy Analysis

We have analyzed the impact of three policies on our long term coal production forecasts: acid rain legislation, reclamation, and severance taxes.

Based on the preceding discussion, we conclude that new contract potential for Montana based upon some form of SO_2 reduction does not seem likely, or is at best very small, to the end of our forecast period. As developed in our main report, on a delivered basis, the cost of reclamation is very small, perhaps averaging 2.0 to 2.5 cents per million BTU out of a delivered price of $1.50 to $1.60 per million BTU. In addition, state/federal rules and guidelines applied in individual sites offer only minor differences between Montana and Wyoming. We conclude that potential changes in reclamation policy are very unlikely to significantly impact coal markets.

The analytical model for our analysis of the changes in the Montana coal severance tax is summarized in Figure S-3. Given the demand for coal, a reduction in severance tax (and price) has two effects: revenue is lost on existing production (area A) and revenue is gained (area C) on new production (taxed at the new reduced rate). As shown, there is a net loss as "A" outweighs "C." In general the extent of net loss or gain depends critically on the shape of the demand function. A convenient statistic used by economist

Figure S-3



A+B= current revenue.
A=lost revenue under tax reduction.
C=revenue on new production.
C−A=net change in tax revenue.

Issue: X=new production level (elasticity of demand)
* Average price of 8700 BTU producers, for example.

to represent the response of quantity demanded to changed price is "elasticity of demand." It can be shown analytically that unless demand is extremely elastic (in fact an elasticity around -4.6), tax reductions on coal will result in a net loss of income to the state. Based on our preceding analysis of price reductions, the demand curve faced by Montana producers is inelastic at least through 1995, and then only barely elastic (around -1.0) in the year 2000.

The net loss for two specific tax reduction policies are shown in Table S-3 for 2% electric growth (base case). For example, in the year 2000 a 50% tax cut on new production results in a loss of $46.5 million (area A of Figure S-3) on new production that would occur anyway and a $12.0 million gain (corresponding to area C) on new production stimulated by the tax cut. The net loss is then $34.5 million per year. Results for all scenarios and years are conceptually similar: new production that will occur anyway dwarfs incremental production stimiulated by a tax cut. In short, with reference to Figure S-3, area "A" is greater than "C" in every case we modeled. Our empirical results are, incidently, similar to those developed by utility consultant Victor Wood, in a report we obtained through the Montana International Trade Commission.

Table S-3 also provides an estimate for another possible policy: a 50% tax cut on <u>all</u> production. In this case an additional annual $48.5 million tax revenue loss on <u>existing</u> production is added to the previously described net loss on new production, for a year 2000 loss of $83.0 million annually.

The net present value of the tax loss under the two policies to the year 2000 can be estimated from the annual losses of Table S-3. A 50% tax cut on new production has a negative present value of $105 to $205 million at 1% to 3% electric growth; a 50% cut on all production has a negative present value ranging from $685 to $785 million.

Table S-3

Summary Tax Policy Analysis

Tax Policy Alternative	Change in Tax Revenues (million \$/year) and Coal Production (million \$/year)							
	1985		1990		1995		2000	
	Tax (10^6 \$)	Coal (mtpy)	Tax (10^6 \$)	Coal (mtpy)	Tax (10^6 \$)	Coal (mtpy)	Tax (10^6 \$)	Coal (mtpy)
A. 50% Tax Cut on New Production:								
Loss on Base Case New Production:			13.5		21.0		46.5	
Tax on Increase in New Production:			3.6	2.4	2.7	1.8	12.0	8.0
Net Effect:			9.9	2.4	18.3	1.8	34.5	8.0
B. 50% Tax Cut on All Production:								
Loss on Existing Production:	48.5		48.5		48.5		48.5	
Net Effect New Production:			9.9	2.4	18.3	1.8	34.5	8.0
Total	48.5		58.4	2.4	66.8	1.8	83.0	8.0

Offsetting the tax revenue losses to the state as a whole are coal production gains (also quantified in Table S-3). An interesting question is the decision weight to be placed on production gains (or profits, or wages, or employment or etc.) as opposed to tax revenue losses. These appear to us to be largely distributive issues which are beyond the scope of our analysis. We have also simplified our study by assuming that there is no move by producers or railroads to capture any profits potentially created by tax reductions, but that in fact reductions show up in delivered prices. Similarly we have adopted a "naive" model in the sense that Wyoming producers and legislators do not strategically respond to Montana tax cuts. Relaxing these assumptions only strengthens our basic conclusion. The main finding here is that tax revenues will in all cases decline on net due to tax reductions.

Montana Coal Market to the Year 2000: Impact of Severance Tax, Air Pollution Control, and Reclamation Costs

Chapter I. Introduction

This paper provides an economic analysis of the market for Montana and Wyoming coal. The basic purpose of the study is to provide a Montana coal production forecast to the year 2000 and show the sensitivity of this forecast to three policies: The coal severance tax, acid rain legislation, and reclamation policies. The focus is entirely on the derived demand by coal-fired plants in the electric utility sector. This category of use currently accounts for about 95% of Northern Great Plains production. As developed in some detail elsewhere (Duffield et al, 1982), the other current and potential users: (industrial, synfuels, and export) are unlikely to be significant before the turn of the century.

For the purposes of our analysis, the electric utility market for coal can be conveniently divided into three categories: existing contracts, new plants, and "acid rain" plants. As summarized in Figure 1, these categories are based on three different vintages of coal-fired generating units. Most of the generating units now being supplied under contract with Montana and Wyoming coal producers were either built under stringent state-specific air pollution standards (mostly in the west) or under the New Source Performance Standards (NSPS) that came into effect on boilers ordered after 1971 (1.2 lbs. of SO_2 per million BTU). New plants coming on line from the mid-1980's on are mostly under the Revised New Source Performance Standards (RNSPS) that are effective on boilers ordered after 1978. The third category of plants, the so-called "acid rain" plants are mostly older plants built under very lenient to nonexisting sulfur emissions. Many of these plants are in the industrialized midwest and currently burn mostly high sulfur Illinois Basin

Figure 1

Montana Coal
Market Overview

Market Sector	Plant Vintage	Typical Sulfur Emission Regulation
1. Contracts	mostly on line from 1968 to the present	less than 1.8 lbs. $SO_2/10^6$ BTU
2. New Plants	Present to 1993 and beyond	Revised New Source Performance Standards (70%, 90% Scrubbing)
3. Acid Rain	Mostly pre-1975	greater than 3.0 lbs. $SO_2/10^6$ BTU

and Appalachian coals. There is a possibility that these plants will be required by federal legislation to either install scrubbers or switch to low sulfur fuels (such as Montana or Wyoming coals).

Each of these basic existing and potential markets for Montana coal (contracts, new plants, and "acid rain") will be discussed in turn. The analysis of existing contracts is described in Chapter II. The focus is on identifying the historical spatial markets for Montana and Wyoming coals and the influence of specific factors on recent trends. Based on known contracts, a short term forecast to 1988 is discussed. The Montana coal market potentially associated with new plants expected to come on line to the year 2000 is described in Chapter III. The "near term" analysis (to 1993) is based on the historical spatial coal market and published summaries of electric utility 10 year plans. A brief analysis of the delivered cost of Montana and Wyoming coal at the Northern States Power's Sherco #3 plant (to come on line in late 1987 in Minnesota) is included in this section. The long term analysis is based on a spatial market model originally developed under a contract with the U.S. Office of Surface Mining (Duffield, et al, 1982). This section also provides a discussion of the magnitude and significance of reclamation costs. In Chapter IV, the potential Montana coal market due to proposed acid rain legislation is discussed. Chapter V is an analysis of the impact of changes in Montana coal severance tax on each of the three market categories identified above: contracts, new plants, and "acid rain."

Chapter II. Existing Contracts

A. Contracts and Market Share

The purpose of this chapter is to examine the historical markets for Montana and Wyoming coal and to explain differences in the growth and distribution of contracts and deliveries.

Existing contracts for Montana and Wyoming coal are summarized in Appendix B. The listing is based on reported deliveries and industry sources. Because contracts are confidential, it is difficult to validate this information.

In order to identify market trends, we have analyzed reported deliveries to all 176 new coal-fired power plants that will have come on line between 1971 and 1985 in the 19 state market* for Northern Great Plains (NGP) coal. This information is summarized in Table 1 for three five-year periods. The basic finding is that the Montana market share has been relatively stable, with Montana producers supplying about 10% of new coal-fired generating capacity in each of the three periods (1971-75, 1976-80, 1981-85). By contrast, Wyoming's share jumped dramatically from 16% in 1971-75 to 53% and 62% in 1976-80 and 1981-85 respectively.

Assuming a 60% capacity factor, a new 500 mw coal-fired plant will use about 1.6 million tons per year (mtpy) of 8700 BTU/lb. Montana coal. On this basis, the mw capacity information is converted in Table 2 to an estimated share of tonnage. The total 176 new plants require 275.3 mtpy. Montana has served about 10% of this capacity or 26.2 mtpy. Wyoming captured 46% or 128 mtpy and other producers (Colorado, Texas, Illinois, etc.) captured 44%. It should be noted that these estimates do not, of course, correspond exactly to current Montana and Wyoming production, which is likely to be around 32 mtpy and 129 mtpy in 1984 respectively. This is in part because the Tables include contracts

* AR, CO, IL, IA, IN, KS, LA, MI, MN, MO, MT, NB, ND, OK, OR, SD, TX, WS, and WY

Table 1

Market Share Summary
for New Coal-Fired Plants
in the 19 State Market Area*

Coal Source	Time Period: On Line Date 71-75	76-80	81-85	Total
Montana				
# of plants	5	9	6	20
mw capacity	1744	3589	2929	8262
share of mw	.080	.095	.107	.095
Wyoming				
# of plants	10	38	35	83
mw capacity	3392	19785	17121	40298
share of mw	.156	.526	.623	.464
Other				
# of plants	31	26	16	73
mw capacity	16664	14255	7420	38339
share of mw	.764	.379	.270	.441
Total				
# of plants	46	73	57	176
mw capacity	21800	37629	27470	86899

* AR, CO, IL, IA, IN, KS, LA, MI, MN, MO, MT, NB, ND, OK, OR, SD, TX, WS, and WY

Table 2

Market Share Summary
for New Coal-Fired Plants
in the 19 State Market Area
(million tons per year equivalents*)

Coal Source	71-75	76-80	81-85	Total
	Time Period: On Line Date			
Montana				
# of plants	5	9	6	20
mtpy	5.5	11.4	9.3	26.2
share	.080	.095	.107	.095
Wyoming				
# of plants	10	38	35	83
mtpy	10.7	62.7	54.2	127.6
share	.156	.526	.623	.464
Other				
# of plants	31	26	16	73
mtpy	52.8	45.2	23.5	121.4
share	.764	.379	.270	.441
Total				
# of plants	46	73	57	176
mtpy	69.1	119.2	81.0	275.3

---

* Based on an assumed 3167.5 tons per year/mw capacity (assumes a heat rate of 10486 BTU/kwh, 8700 BTU coal, at 60% capacity factor).

for plants coming on line in 1985, and because new plants were allocated on the basis of deliveries in the last year of each period (1975, 1980, and current). In some cases deliveries to new plants in 1975 and 1980 are being made by another supplier at present. In addition, some current deliveries are being made to plants on line before 1971 and actual capacity factors can vary significantly by year. The purpose of the tables is to provide a consistent picture over time of the Montana and Wyoming market shares based on deliveries to new plants.

The main finding here is that the Montana market has been small, but stable, compared to Wyoming production which increased six times as fast as Montana after 1976.

B. Market Factors

There are a large number of potentially significant market factors that could explain these differences. A partial list is provided in Figure 1. Here the market factors are sorted by coal characteristics versus political and economic events. A common misconception is that the only difference between Montana and Wyoming coals are coal severance tax rates. In fact any or all of the listed factors could affect the respective markets in different ways.

Coal Characteristics

Some basic characteristics of Montana and Wyoming coals are listed in Table 3. There are in fact at least four distinct coals. The Montana Powder River Basin coals centered around Colstrip, Montana at 8700 BTU/lb. and .7% sulfur are fairly similar to the Powder River Wyoming coals averaging 8400 BTU's and .4% sulfur. Average FOB prices of these two coals are fairly similar at around 60¢/MMBTU. The other Montana coal is Decker/Spring Creek; this is higher BTU and lower sulfur coal and commands a price premium of 20¢ to

Figure 1A

Market Factors

A. Coal Characteristics

Location

BTU Content

Sulfur

Ash/Moisture

B. Key Political and Economic Events of 70-84

Clean Air Act of 1970

Arab Oil Embargo, 73-74 oil price rise

Rail Escalation

Coal Severance Taxes

Nuclear Decline

Electric Demand Slowdown

Revised New Source Performance Standards (1978)

Table 3

Some Characteristics of Montana and Wyomming Coals

	BTU	% Sulfur	$/Ton FOB (1983)	¢/MMBTU
Montana				
Western Energy			11.13	
Westmoreland	8700	.7	10.77	64.0
Peabody			10.90	
Decker	9600	.34	19.31	100.6
Spring Creek	9000	.34	15.96	89.7
Wyoming				
Powder River	8400	.4	9.72	57.9
South Wyoming	10500	.6	30.31	144.3

40¢/MMBTU. The other Wyoming coal is south Wyoming, which is bituminous in rank (10,500 BTU), low sulfur and much higher in price (144.3¢/MMBTU).

Location Advantage: Spatial Market

The locations of the Powder River coals with respect to Burlington Northern Railroad are shown in Figure 2, and with respect to the Minnesota market in Figure 3. The main thing to note here is that for shipments east to Minneapolis Colstrip area coal has a 240 mile edge over Wyoming Powder River. However, to the south (Texas, Oklahoma, etc.) Gillette area coals have a 330 mile advantage. At the current average rate for coal unit trains of .017 $/ton-mile, the respective advantages are 4.08 $/ton to Montana to the north-central states and a 5.61 $/ton advantage to Wyoming to the south-central states. This difference is very important and has the same impact on delivered price as an equivalent difference in FOB mine price. Table 4 shows the relative cost differences associated with location advantages. Because of these very important locational differences vis-a-vis markets and existing rail routes, there are strongly defined spatial markets for Montana and Wyoming coals. This point will be developed in greater detail in Chapter III below; however, it is useful at this point to note as an example the areas where Montana and Wyoming coal are least cost (on a delivered basis) with a $9.50 Montana FOB price and $7.70 Wyoming (see Figure 4). Basically Montana picks up the north-central states and Wyoming has the market roughly south of the Minnesota-Iowa border.

While location is probably the key characteristic in explaining coal spatial markets, BTU and sulfur are also significant. Because Decker is higher BTU per ton than Colstrip and Gillette area coals (and because it is only 125 miles north of Gillette rather than 330), Decker can potentially compete to the south (assuming similar FOB) at distances over 1000 miles (Texas) with lower BTU Gillette coals. South Wyoming coals and, to a lesser extent, Decker also

BURLINGTON NORTHERN RAILROAD
serves the
POWDER RIVER BASIN

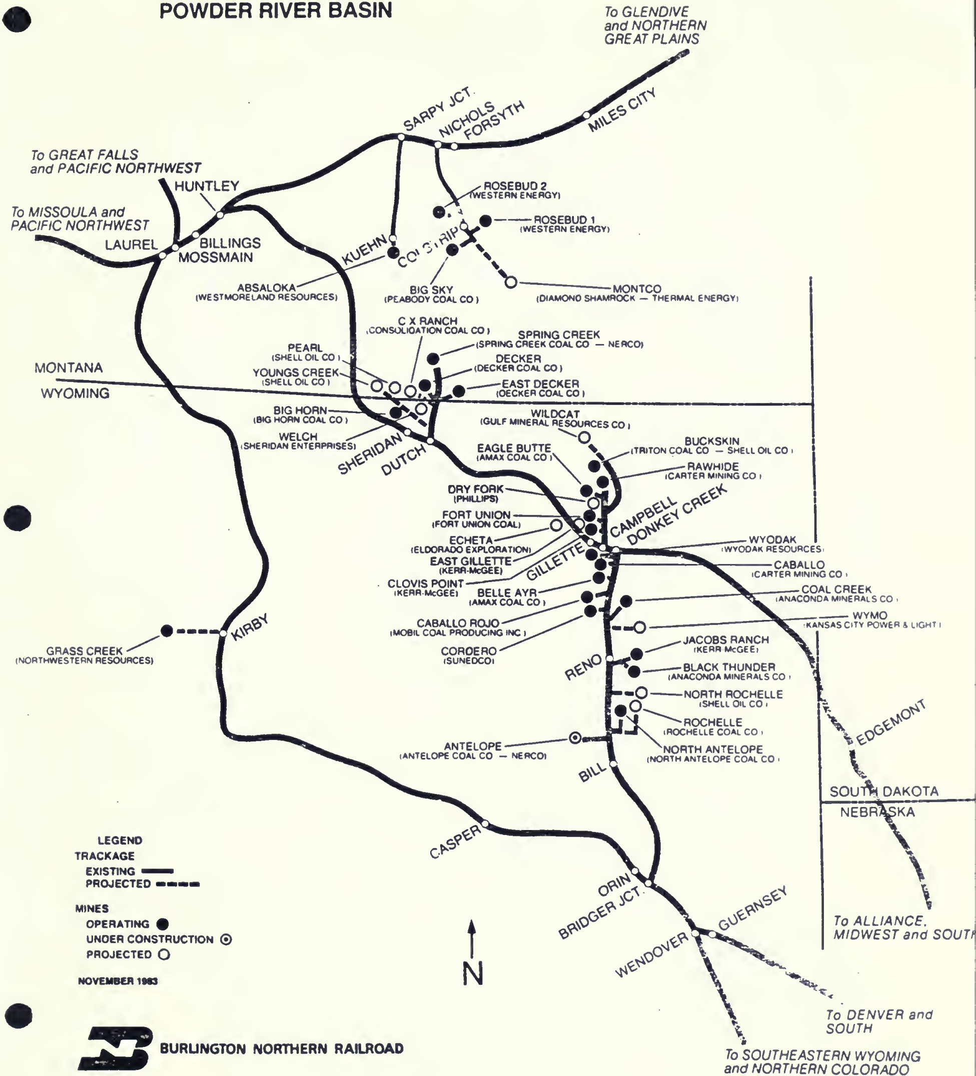
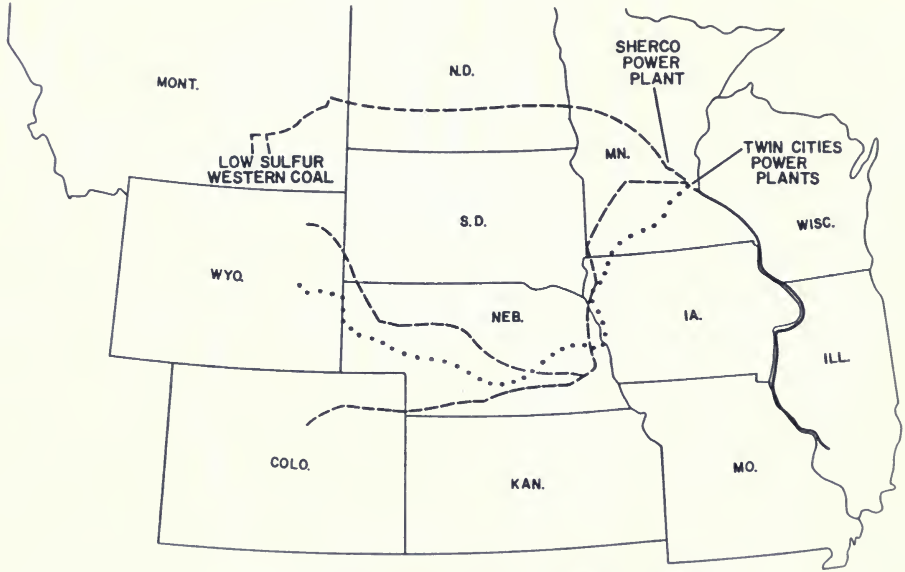


Figure 3



NORTHERN STATES POWER COMPANY
MAJOR COAL SOURCES AND TRANSPORTATION ROUTES

LEGEND

B.N. =

CNW & U.P. =

SO. ILL. =

Table 4

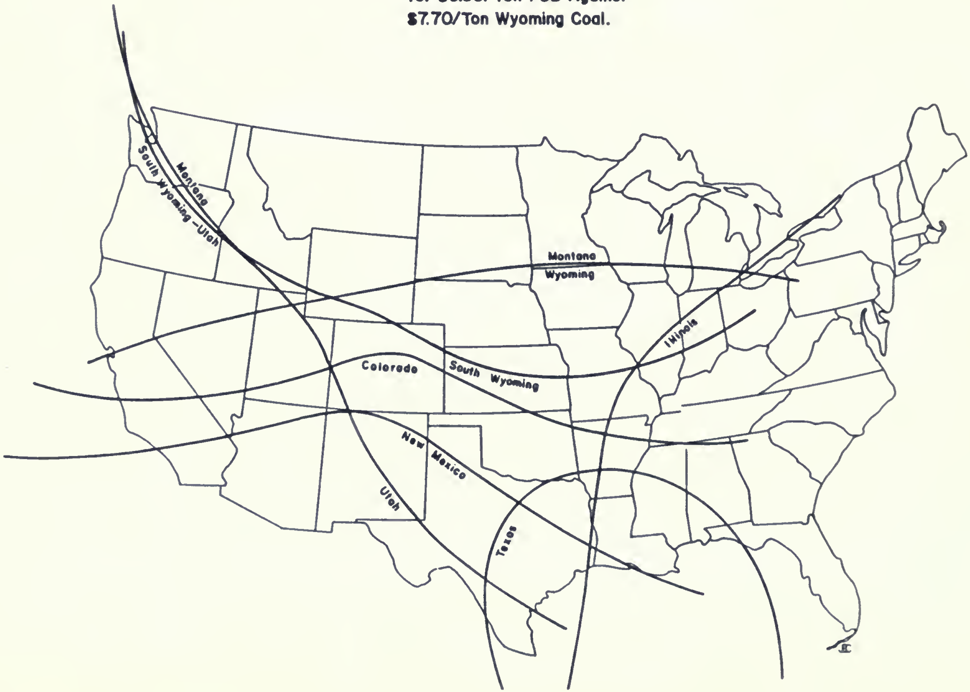
$/Ton Equivalents of Rail Mileage Differentials

Mileage Differential	*$/Ton Equivalent
50	.85
100	1.70
150	2.55
200	3.40
250	4.25
300	5.10
350	5.95

* at .017 $/ton-mile

Figure 4

Montana Coal Market Area
for $9.50/Ton FOB Against
$7.70/Ton Wyoming Coal.



command a price premium because they are low sulfur but can be burned in boilers designed for some bituminous coals. On the other hand, Colstrip coals are higher sulfur (.7% to .8%) than Gillette (.3% to .4%). Even this relatively small difference in sulfur content can be significant. Under the NSPS of 1.2 lbs. $SO_2/10^6$ BTU, Montana coal that averages greater than .6% sulfur cannot be burned without scrubbing or blending with even lower sulfur coal. For example, at the Wisconsin Power and Light Columbia plants Colstrip coal is cheaper at 29.07 \$/ton delivered (or 168.5¢/MMBTU in 1984) than Wyoming coal (Belle Ayr at \$31.97/ton or 188.2¢/MMBTU in 1984). However, Colstrip at .8% sulfur is apparently blended with .35% sulfur Wyoming coal to meet the 1.2 standard.

Another example is the Interstate Power Lansing plant in Iowa. Wyoming Coal is blended with Illinois coal that is 44.3¢/MMBTU cheaper but 2.76% sulfur. Blending Montana coal at this plant (under a 1.94 SO_2 reg.) would reduce by about half the share of cheap high-sulfur Illinois coal that could be burned. The net saving to using Wyoming coal here is around \$840,000 even assuming equal Montana and Wyoming delivered prices. In short, the slightly higher sulfur content of Montana coals can be significant at some burn sites.

The importance of locational advantage appears to be supported by state-level information on new plants that burned Montana and Wyoming coal 1971-1985. There are only six states where new plants burned Montana coal in this period: Illinois, Michigan, Minnesota, Montana, Texas, and Wisconsin (Table 5). This is consistent with the sample spatial market map noted previously (Figure 4). It should be noted that North Dakota and South Dakota are dominated by mine mouth North Dakota lignites. Only Minnesota and Montana are solidly in our market while Texas, Illinois, and Wisconsin are on the market boundary. The share of Michigan is due to our location and advantage in northern Minnesota since this coal goes by lake steamer from Duluth/Superior

Table 5

Montana Contracts to New Power
Plants by Period

	71-75		76-80		81-85	
	units	1000 mw	units	1000 mw	units	1000 mw
A. <u>South Central Oil Gas States</u>						
Texas	0/4	0/2372	2/17	966/10029	1/8	176/4042
MT share	.00	.00	.12	.10	.13	.04
B. <u>Residual States</u>						
Illinois	2/7	465/4125	0/5	0/1849	0/1	0/600
Michigan	0/7	0/3620	3/4	270/1040	3/4	1353/1411
Minnesota	1/1	365/365	3/3	1995/1995	0/0	0/0
Montana	1/1	358/358	1/1	358/358	2/2	1400/1400
Wisconsin	1/1	556/556	0/2	0/1173	0/3	0/1282
<u>Subtotal</u>	5/17	1744/9024	7/15	2623/6415	5/10	2753/4693
MT share	.29	.19	.47	.41	.50	.59
<u>Total</u>	5/21	1744/11396	9/32	3589/16444	6/18	2929/6705
MT share	.24	.15	.28	.22	.33	.44

to lakeside Detroit Edison plants. Similarly, the locational advantage to Wyoming is indicated in its historical market share for states south of and including Nebraska and Iowa (Table 6).

<u>Oil and Gas Price Escalation</u>

While location is clearly important, it is possible with the state-level data on new plants to also investigate several of the other factors listed in Figure 1. It appears that the main cause of the large jump in Wyoming production after 1975 is not due to intrafuel competition (e.g. Montana vs. Wyoming coals) but to interfuel substitution. Specifically, the very large increase in oil and gas prices following the Arab oil embargo of late 1973 drastically altered the market for electric utility fuels. The most vulnerable states were the south central oil and gas states of Texas, Oklahoma, Arkansas, Louisiana, and (to a lesser extent) Nebraska. These states historically have burned very little coal and were not building coal-fired plants in 1971-1975. As shown in Table 6, only four new coal units were added in Texas (supplied by Texas lignite). However, in response to new oil and gas prices (and relatively high electric consumption growth rates in the Sun Belt), a large amount of coal-fired capacity was added in these states after 1976.

Prior to 1976 Wyoming captured no new coal-fired units in these states (even though it was a least-cost coal source at many sites) because no new units were built. Since 1976, Wyoming's share of the five south-central gas states has been around 70% to 80% and has accounted for 66.1 mtpy or 53% of Wyoming's new plant tonnages (totaling 124.9, Table 7). This interfuel substitution plus location also has relevance for other states such as Kansas (where some coal has been burned historically) and for Oregon, where coal is competitive against incremental hydro and nuclear.

Table 6

Wyoming Contracts to New Power
Plants by Period

	71-75		76-80		81-85	
	units	1000 mw	units	1000 mw	units	1000 mw
A. South Central Oil Gas States						
Arkansas	0/0	0/0	2/2	1262/1262	3/3	2422/2422
Louisiana	0/0	0/0	0/0	0/0	5/5	2793/2793
Nebraska	0/0	0/0	3/3	1306/1306	3/3	835/835
Oklahoma	0/0	0/0	6/6	3178/3178	4/4	1787/1787
Texas	0/4	0/2372	11/17	5282/10029	4/8	2012/4042
Subtotal	0/4	0/2372	22/28	11028/15775	19/23	9849/11879
WY share	.00	.00	.79	.70	.83	.83
B. Residual States						
Colorado	1/2	282/514	1/5	396/1765	2/3	802/1202
Iowa	2/2	880/880	3/3	1480/1480	3/4	1442/1592
Kansas	2/3	462/1434	3/3	2162/2162	3/3	1210/1210
Missouri	0/4	0/2463	1/5	726/2762	2/2	905/905
Oregon	0/0	0/0	1/1	530/530	0/0	0/0
Wisconsin	0/1	0/556	2/2	1173/1173	3/3	1282/1282
Wyoming	5/5	1668/1668	4/4	1897/1897	3/3	1167/1167
Subtotal	10/23	3392/10031	16/31	8759/15608	18/24	8177/11110
WY share	.43	.34	.52	.56	.75	.74
Total	10/27	3392/12403	38/59	19787/31383	37/47	18026/22989
WY share	.37	.27	.64	.63	.79	.78

Table 7

Summary 1971-1985
Contracts to New Power Plants
(Million tons per year equivalents)

	Montana tonnage	Montana Market share	Wyoming tonnage	Wyoming Market share
A. South Central Oil Gas States				
Arkansas			11.7	1.00
Louisiana			8.8	1.00
Nebraska			6.8	1.00
Oklahoma			15.7	1.00
Texas	3.6	.07	23.1	.44
Subtotal	3.6	.07 (of 52.1)	66.1	.70 (of 95.1)
B. Other States				
Colorado			5.0	.45
Illinois	1.5	.07		
Iowa			12.0	.96
Kansas			12.1	.80
Michigan	5.1	.27		
Minnesota	7.5	1.00		
Missouri			5.2	.27
Montana	6.7	1.00		
Oregon			1.7	1.00
Wisconsin	1.8	.18	7.8	.81
Wyoming			15.0	1.00
Subtotal	22.6	.35 (of 63.8)	58.8	.70 (of 84.4)
Total	26.2	.23 (of 115.9)	124.9	.70 (of 179.49)

By contrast (Table 5), Montana is by location at a $5 to $6/ton disadvantage to the south-central oil and gas states and did not share in the oil price-induced boom that Wyoming coal experienced. As noted in Table 5, Montana has had a small share of the Texas market. This is mostly Decker/Spring Creek which is higher BTU and much closer to Gillette (as explained earlier).

Excluding the oil and gas states, the market shares for both Wyoming and Montana (in their respective markets) have increased. For Montana, on a mw basis, the share was 20%, 40%, and 60% in 1971-75, 1976-80, 1981-85 respectively (Table 5); and for Wyoming 35%, 55%, and 75% respectively. In short, both Montana and Wyoming market shares, excluding the oil and gas states, have increased in their respective markets. The biggest difference between the two states is that historically Wyoming has a locational advantage to the south, where growth and substitution out of oil and gas have been the greatest. Excluding Texas, only 42 plants were built between 1971 and 1985 in the five states where Montana has delivered to new plants. By contrast, 133 plants were added in the 12 states where Wyoming has locational advantage.

SO_2 Emission Regulations

Another significant factor in the Montana and Wyoming coal markets from 1971-1985 was the establishment of sulfur emission standards for new coal-fired plants. The first standards (NSPS) were on boilers ordered after 1971 and requiring a 1.2 lbs/MMBTU standard. This meant that burning low sulfur coals was a permissable strategy. However, as noted previously, mainly the Decker/Spring Creek coals (at .3% to .4%) have benefited from this legislation as the Colstrip area coals run around .7% to .8% sulfur. The second set of standards (RNSPS) on boilers after 1979 required 70% scrubbing on low sulfur

coals and 90% on high sulfur. The effect of these regulations should be to lessen the market for both Wyoming and Montana vis-a-vis the high sulfur Illinois Basin coals and take away most of the disadvantage of the Colstrip area coals vis-a-vis slightly lower sulfur Wyoming Powder River coal.

In assessing any of the political and economic market factors (Figure 1) one needs to know how early coal sourcing decisions are made vis-a-vis on line dates. For example, were the new plants that came on line in 1976-1980 reflecting current prices and policy? Prices and policy from five years earlier? Some partial information on this is provided in Table 8 and Table 9*. From Table 8, almost 90% of new coal-fired plant (120 of 137) prior to 1975 came in under lenient sulfur regulations. Between 1976 and 1982 7 of 104 or 7% came in under lenient standards, and after 1982--none. The lag between boiler order date (Table 9) and on-line date has apparently increased from 5.2 to 8.3 years. These are probably approximate estimates of lead times for aspects of the coal sourcing discussion, at least to the level of selecting rank if not specific source. Based on these tables, one would expect to see the effects of the NSPS showing up as early as the 1976-1980 new plant market shares and the RNSPS only beginning to impact the end of the 1981-1985 period.

Before trying to identify the net effect of new air emission regulations, it is useful at this point to summarize the policy effects that were indicated in Figure 1. In Figure 5, the effects of specific political and economic events is summarized both for intra- and inter-fuel substitution. As noted previously, the large interfuel substitution effect on the Wyoming market has been at least partially isolated by separating out the south-central oil and gas states. As noted previously in Tables 5 and 6, the market shares of both

*These tables include Washington and Idaho to make a 21 state market area.

Table 8

Classification of Coal-Fired Plants in
21 State[f] Market Area by
On-Line Date and Sulfur Emission Regulation

On-Line Date	Total	Sulfur Regulation: Greater than 1.2 lb/10^6 BTU	NSPS or 1.2 lb/10^6 BTU	RNSPS	PSD and/or less than 1.2 lb/10^6
1960-1975	137	120	12[a]	0	5[b]
1976-1982	104	7[c]	78	0	19
1983-1986	49	0	14[d]	26	9
1987-1990	34	0	0	33	1
Totals	324	127	104	59	34[e]

Source: Derived from Appendix B, Duffield, et al, 1982.

Notes

[a] These are all Wyoming and Colorado plants built to meet state standards.

[b] Wyoming plants built to meet state standards of .2 to .5 and a 1.0 Montana PSD plant.

[c] Missouri and Indiana plants, mainly 2nd or 3rd units ata a given site.

[d] Indiana, Iowa, Louisiana, Michigan, Texas, and Wisconsin plants that appear to have been ordered by 11-78; usually 2nd unit.

[e] Eleven PSD plants (Montana, Washington, Kansas, Minnesota); 18 more stringent state standards in the west (Montana, Wyoming, Colorado, N.D.) and 5 more stringent Arkansas and Missouri plants.

[f] Arkansas, Colorado, Illinois, Idaho, Indiana, Iowa, Kansas, Louisiana, Michigan, Minnesota, Missouri, Montana, Nebraska, North Dakota, Oklahoma, Oregon, South Dakota, Texas, Washington, Wisconsin, Wyoming.

Table 9

Distribution of Time Lag Between Boiler Order Date
and On-Line for Coal-Fired Steam Plants in a
21 State Market Area

	Sample	
Years Lag	Plants Built 1960-1982	Plants Proposed 1983-1990
3	3	
4	5	1
5	8	2
6	7	2
7		3
8	2	1
9	1	
10		3
11		1
12		3
Mean	5.23	8.25
Standard deviation	1.48	2.66
Approximate 90% Confidence Interval	3 to 7-1/2 yrs.	4 to 12-1/2 yrs.

Source: Derived from Appendix B, Duffield *et al*, 1982.

Figure 5

Policy Effect of Fuel Choice

Event	Interfuel Substitution	Intrafuel Substitution	
	Coal vs. other fuels	NGP vs. other coals	MT vs. WY
A. Oil and Gas Price Escalation:			
1. New Coal-fired plants in the south-central states	+ Coal	+ NGP	++ WY
2. Rail Rate Escalation	- Coal	- NGP	neutral
B. SO_2 Emission Regulations:			
1. NSPS-1971	- Coal	+ NGP	+ WY + Decker
2. RNSPS-1978	- Coal	- NGP	+ MT
C. Coal Severence Taxes	- Coal	- NGP	- MT
D. Nuclear Decline	+ Coal	neutral	neutral
E. Electric Growth Down	neutral	neutral	neutral

Montana and Wyoming increased strongly 1971-75 to 1976-80 and and 1976-80 to 1981-85. Looking at the factors in Figure 5, the negative indicators for NGP as a whole are rail escalation, RNSPS, and coal severance tax. The positive are NSPS and possibly the positive effect of oil and gas substitution in residual states. Since both Montana and Wyoming increased their shares of their respective markets in 1976-80 and again 1981-85, it appears that the expected market expansion due to NSPS dominated the potential market contracting effects of rail escalation and coal severance taxes.

The NSPS also appear to explain the mixed pattern of state specific changes that have been tabulated (referring again to Table 5). Between 1971 and 1985 Montana's share increased in Texas and Michigan, declined in Illinois and Wisconsin and was stable at 100% in Montana and Minnesota. The first thing to note is that the increases in Michigan and Texas were for Decker and Spring Creek coal. These coals are .3% to .4% sulfur and could, of course, be burned without scrubbing to meet NSPS. They compete with the low-sulfur Wyoming fuels and, having a locational advantage to Duluth, pick up Michigan after NSPS were instituted. To Texas, the distance advantage to Gillette is only 130 miles and as noted can be largely overcome by Decker and Spring Creek higher BTU. This has given these coals a small but stable share of the Texas market. Given limits on capacity and reserves for these coals, the mines are apparently allocating their production to obtain premium prices in their best markets.

In Wisconsin the change is again due to NSPS. The new plant on line in Wisconsin in 1971-75, the Columbia unit #1, was not under NSPS and could burn Montana's .7% S coal without scrubbing. However, a Columbia unit #2 in 1978 came under NSPS and went to Wyoming .41% S coal, which didn't require

scrubbing. In 1982, the cost of scrubbing NGP coal (in 1980 dollars) for 70% to 90% removal was \$5 to \$8 per ton or 28¢ to 48¢ per million BTU. Of course, to meet NSPS with .7% to .8% S coal, less than 50% scrubbing would be required. However, at the time the coal source decision was made on Columbia unit #2, scrubber technology was not as well developed and cost estimates were probably higher. The prices for delivered coal at the Columbia units in 1979 were 84.8¢ (Montana) and 121.1¢ (Wyoming) or a 36.3¢/MMBTU difference. In 1980 the price difference was 29.8¢. The cost and uncertainty associated with scrubbers appears to justify and explain the choice of Wyoming coal at new units in Wisconsin under NSPS.

By comparison, in 1980 the average FOB price for Rosebud County, Montana coals was \$6.96. At this price the Montana severance tax and the Wyoming severance tax would amount to about \$1.53 and \$.73 respectively or an \$.80 difference. In cents per million BTU's this amounts to 4.6¢ difference in 1980. It would appear that at least in Wisconsin, the severance tax effect is an order of magnitude short of explaining the shift in market share.

The shift in Illinois also appears to be related to NSPS. Both of the new Illinois plants that burned Montana coal in 1971-75 were under low-sulfur regulations, but 1.8 lb./SO_2 state standards rather than 1.2 lb. NSPS. For example, the Edwards plant (unit 3 on line in 1972) could burn .7% to .8% S Montana coal and meet the standards. The other coal at this plant through the years has been mainly Kentucky low-sulfur coal. (Interestingly, this contract was lost to Kentucky in 1984 due to a \$13 decrease in delivered price resulting from a cut in rail rates.) The other new plant in Illinois was Powerton (units added in 1972 and 1975). As of 1976, Decker coal was blended

with high sulfur Illinois at 102¢ and 57¢ per million BTU respectively. More recently southern Wyoming 9600 BTU coal has also be burned at this plant. For example, in 1979 Illinois, Montana, and Wyoming were 76.2¢, 166.1¢ and 197.5¢ per million BTU respectively. The price differential here between Illinois and the western coals is on the order of 90¢ to 121¢. In 1980 the differential was 145.2¢ per million BTU. By comparison, estimated scrubber costs for 3.4% S Illinois coal to meet NSPS in 1980 were $15.43/ton or about 73¢/MMBTU. In short, in 1980 and earlier scrubbers were significantly cheaper than western coal. An examination of the six Illinois plants that came on line 1976-1985 indicates that all chose high sulfur Illinois/Indiana coals plus scrubbing over the Montana or Wyoming coals. This appears justified by the economics of delivered price differentials (145.2¢) versus scrubbing (73¢) or a 72¢/MMBTU advantage to scrubbers for a Powerton site. The economics will vary of course by location. Again, it might be noted that a 23% effective severance rate tax (here on Decker's average 1980 FOB price of $15.43) amounts to 18¢/MMBTU which is small compared to the scrubber advantage.

NSPS did not shift the new plant share in the two remaining states of the Montana market: Montana and Minnesota. The Montana plants are Colstrip 1 through 4, all of which faced state and federal emission standards that were more stringent than 1.2 lbs. SO_2/MMBTU and required scrubbing in any case. (This is not to mention the substantial transportation differential against Wyoming coals to Montana.) There has only been one Minnesota plant to come on line under the NSPS. The Clay Boswell #4 unit on line in 1980 went for .7% S Montana coal with scrubbing. The economics were probably close on this versus Wyoming coal based on the Wisconsin numbers. In 1981-85 no utilities in Minnesota added new units under NSPS so there is no evidence on that recent market.

As noted previously, the RNSPS have had little effect on the market shares for the 1971 to 1985 new plants (no more than 5 of these 176 plants are under RNSPS). The dominant feature of the RNSPS is that now all low sulfur coals must be scrubbed 70% (and high sulfur 90%). For typical Powder River coals this amounts to an estimated \$6.25/ton or 35¢/MMBTU penalty against high sulfur coals in 1984 dollars. In fact the RNSPS improve the relative position of the typical .7% sulfur Montana coals against .3% to .4% Decker and Wyoming coals. However, the NGP market as a whole will shrink. Based on known contracts for 30 RNSPS plants to come on line in the 19 state market by 1993, only 8/30 or 27% are taking NGP coals. This contrasts with the 1971-1985 average of 103/176 or 59% and the NGP share of low sulfur regulation plants (less than 1.8 lbs. SO_2/MMBTU) of 58/83 or 70%. A preliminary analysis of the RNSPS plants indicates that states on the market boundary, such as Indiana, Illinois, Louisiana, Texas, Michigan, Iowa, and Missouri will be less likely to buy NGP coal than in the past.

C. Summary

The major conclusions from this analysis of market share are as follows. The Montana coal market share through the 1971-1985 period has been small but relatively stable due to the locational advantage in Minnesota, Wisconsin, Michigan and by wire to the PNW. The very large relative growth in Wyoming is due to three factors: 1) locational advantage to a much larger market including the south-central oil and gas states, 2) major shifts from oil and gas generation to coal due to rising world oil prices, and 3) the expansion of the low sulfur coal market under the NSPS of 1973. As developed in some detail, only the Decker and Spring Creek coals in Montana benefited significantly in this period from the NSPS. Changes in the Montana coal market share by state

for new plants in this period were analyzed. No cases were identified where the small difference between Montana and Wyoming coal severance taxes were a significant factor.

Chapter III. New Plants

In this chapter the Montana coal market change due to new plants coming on line in the near term and long term will be described.

A. Near Term Contracts

The contract deliveries that were used in Chapter II to analyze historical market share are also the best basis for short term forecasts. Because of the lead time between contracts and on-line dates for plants of at least three to four years, mines already have a fairly good idea of production levels out to around 1990.

Short-run forecasts based on discussions with industry sources and reported contracts for Montana and Wyoming are provided in Table 10. Montana mines expect to expand production from an estimated 32.3 mtpy in 1984 to 41.6 mtpy by 1988. The production decline from 1981 to 1983 is in part the national recession as reflected in capacity utilization at coal-fired plants. Utilities have been taking deliveries at contract minimums and also taking advantage of the spot market. Electrical generation in Minnesota, as an example, actually declined from 1981 to 1982 and in 1983 was still below the 1981 level. The 1981-88 growth rate for Montana is 3.2% annually compared to 4.4% for Wyoming. Montana as a share to Wyoming was .32 in 1981 and is projected to be .30 in 1988. It appears, based on industry sources, that the Montana coal industry is in for a period of steady growth for the next few years.

NERC Coal Unit Additions

A more complete picture of the potential Montana production due to new coal-fired units can be derived from National Electric Reliability Council (NERC) data. NERC publishes annually summary statistics on utility ten year

Table 10

Short Term Forecasts for
Montana and Wyoming: Coal Production
(mil. tons)

Coal Source	1981	1983	1984*	1988	1990
Montana:					
Decker, Spring Creek	15.07	12.46	12.74	16.63	--
Peabody, Western Energy, Westmoreland	15.95	15.95	19.34	24.69	--
Total	33.19	28.68	32.31	41.59	--
Wyoming:					
Total	102.7	112.2	129	139.5	145

Growth Rate	81-88	83-88
Montana	3.2%	7.4%
Wyoming	4.4%	4.4%

*preliminary

Source: Jim Oppedahl, Office of the Governor, Montana and Richard Jones, Wyoming Geological Survey.

plans for capacity additions. Given the lead time to bring a new coal-fired unit on line these plans are an upper limit to new capacity additions. A summary comparison of the two most recent NERC reports for the total U.S. coal-fired additions is provided in Table 11. The nine years that overlap in the 1983 and 1984 forecasts are compared. In just one year the forecasts are down by 44.1 mtpy equivalent or 23% due to delay in unit on line date or project cancellation. The growth rate implicit in the first forecast is about 3.2% and in the second 2.5%. The point here is that the ten year forecasts are an upper limit given miminum lead time plus the potential for slippage and cancellation. Secondly, key determinants of coal production in the long run are clearly coal-fired capacity additions and the growth rate of electrical generation. Both of these are quite volatile and difficult to predict as is apparent here. Our approach in the longer term modeling below is to look at a range of electrical forecasts for 1%, 2%, and 3% electric growth.

Based on the NERC reports, an upper limit estimate of uncommitted new coal-fired capacity in the market area 1985-1993 is reported in Table 12. In the historical Montana new plant market (as developed in Chapter II) of Montana, Illinois, Michigan, Minnesota and Wisconsin, there are only 2 new units totaling 1172 mw or 3.7 mtpy potential that is not currently contracted. Texas is tabulated here in the Wyoming market with 11 units and 21.2 mtpy. The basic picture is that the uncommitted tonnage associated with new plants in the historical 19 state market for NGP coal is small--only 47 mtpy for the next nine years. Almost half of this is in Texas, which is now almost certainly out of the NGP market due to scrubber reqirements. As will be seen below, even a $3 reduction in Montana price would only extend the Montana market beyond historical limits to include parts of Iowa, Nebraska, Missouri and Indiana.

Table 11

Comparison of NERC Forecasts for U.S. Total New Coal-Fired Generating Capacity 1984-1992

Year of Forecast	# Units	mw Capacity	mtpy* coal (equivalent)
1983	115	61,300	194.2
1984	89	47,386	150.1
Difference	26	13,914	44.1

*Assumes 3167.5 tons/mw-year.

Table 12

1985-1993
Uncommitted New Coal-Fired Capacity in
19 State Market

Market*	#Units	mw Capacity	MM tons/year**
A. Montana			
Minnesota	1	772	
Wisconsin	1	400	
Subtotal	2	1,172	3.7
B. Wyoming			
Arkansas	1	836	
Colorado	4	1,485	
Indiana	2	859	
Iowa	1	550	
Louisiana	2	1,340	
Missouri	4	900	
Oklahoma	2	1,140	
Texas	11	6,688	
Subtotal	27	13,798	43.7
C. Total	29	14,970	47.4

*NONE in Montana, Illinois, Michigan, North Dakota, South Dakota, Nebraska, Kansas, Oregon, Wyoming.

**Assumes 3167.5 tons/mw-year.

But these states are only adding 7.2 mtpy of capacity. To conclude, the potential new generation capacity for Montana coals in the near term ranges from 3.7 mtpy to 10.9 mtpy for even very large price reductions.

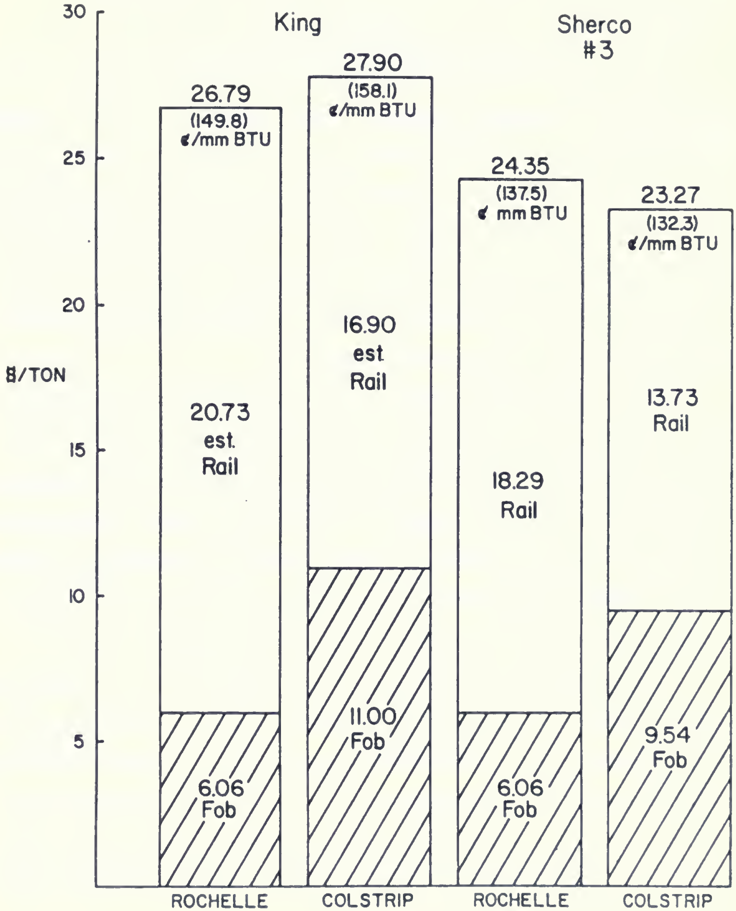
B. Sherco Unit #3

The two new units that comprise the market potential to 1993 in Wisconsin and Minnesota are Northern State Power (NSP) Sherco #3, on line in late 1987; and NSP's Wisconsin Coal #1 slated to be on line 5/93. The timing of the NSP unit projected for 5/93 will depend on electric generation growth and may well be rescheduled to 1995 or later. In short, it is possible that to 1993, the only new plant that Montana 8700 BTU coal producers may pick up is Sherco #3. In fact bids have been taken on this plant in November 1984 and a contract will be let in April 1985 for 1.5 to 2.5 mtpy.

Recently NSP signed a contract with a new Wyoming mine, the Rochelle mine, for 1 mtpy to be delivered to its Minneapolis/St. Paul area plants. This has raised questions about whether Montana will maintain its market share in Minnesota. In Figure 6 we provide a comparison of actual and estimated delivered prices at an older NSP plant in Minneapolis (King) and at Sherco #3. We will compare Rochelle and Western Energy (Colstrip) coals. Since BTU's are similar, we present the analysis in $/ton for convenience.

Actual delivered prices at King in 1984 were $27.90 Colstrip and $26.79 Rochelle. Based on the average Colstrip FOB of 11.00, we estimated rail at 16.90. Rochelle benefits from the CNW rail expansion into the Powder River. NSP has indicated that BN and CNW rates are similar, but that CNW may be 1 mill/ton-mile lower. Using this information and the actual rail mileages, we estimate CNW rail at $20.73 and derive a $6.06 $/ton FOB for Rochelle. Industry sources indicate this is a fairly accurate estimate. The difference

Figure 6



MOTANA vs. WYOMING DELIVERIES TO
NORTHERN STATES POWER

here is only \$1.11 \$/ton or cents per million BTU (Colstrip 8824, Rochelle 8942 BTU/lb. on August 1984 shipments) 158.1¢ versus 149.8¢ or 8.3¢.

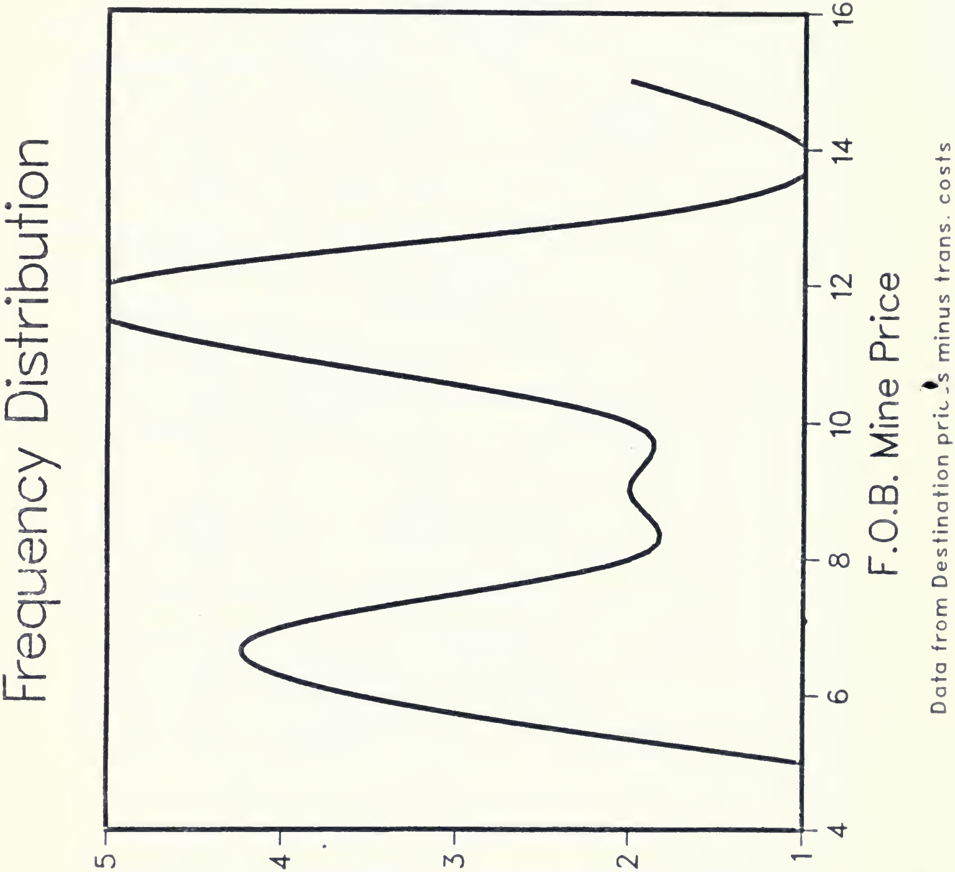
The Rochelle mine is probably as competitive in Minneapolis as any Wyoming mine. It is higher BTU than average (8900 vs. 8400), it benefits from the CNW, and the FOB is at the bottom end of the frequency distribution for Wyoming coal prices. The latter is illustrated for a sample of derived 1984 Wyoming FOB's in Figure 7. The main finding is that the distribution is bimodal at around \$7/ton and \$11-\$12 per ton. The lower prices are reflecting major price reductions on new contracts out of Wyoming, possibly due to large excess capacity of 60 to 80 mtpy and the current soft coal market. For perspective, the average Wyoming FOB for Powder River mines is close to \$10.00 and the new contract average is around \$7.70, but Rochelle to NSP is \$6. By comparison the Montana average FOB is around \$11 and only exceeds Rochelle in delivered price by \$1.11 at King. In short, modest price reductions by Montana coal producers in the Minneapolis area of only around \$1 will continue to make them competitive even against a \$4 Wyoming reduction (to \$6) with CNW service.

For Sherco #3, delivered price is reported in Figure 6 based on Colstrip actual deliveries to Sherco #1 and #2 of \$23.27. Industry sources indicate rail is 13.73 (or 1.8¢/ton-mile) implying a \$9.54 Montana FOB. Sherco #3 is in Becker, Minnesota, which is not served by CNW. Accordingly, we have assumed that rail rates from Montana and Wyoming will be the same. On this basis, and assuming Rochelle bids \$6.06, the Rochelle delivered is \$24.35 or \$1.08 above Colstrip. In cents per million BTU it is 132.3¢ Montana and 137.5¢ Wyoming, or 5.2¢ advantage to Montana.

It appears that Montana has the edge at Sherco #3, but only by a slim margin at the assumed prices. The interesting question here concerns the potential for price reduction at Montana mines. If some Wyoming producers are

Figure 7

Frequency Distribution of 1984
Wyoming FOB Mine Prices



cutting prices from $10 to $6 and opening new mines at $6, what are possible competitive prices out of Montana given 1983 average FOB of $11.00. There may well be significant differences in production costs across mines due to overburden ratios, seam thickness, and mine scale. However, it may also be that there is potential for significant price reduction (at least on incremental production) by Montana producers.

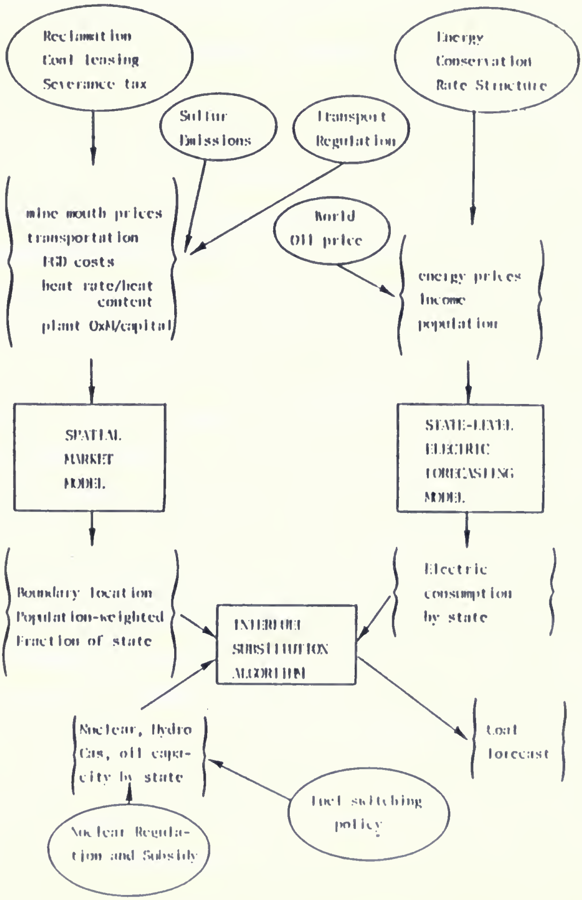
C. Long-Term Forecast

While contracts and known coal-fired additions are the best basis for short-term forecasts, a long run projection requires a more formal model. The basic forcasting model used in this analysis was originally developed under a contract with the U.S. Office of Surface Mining (Duffield et al, 1982). The model provides estimates of the derived demand for coal by the electric utility sector. This end use accounts for 95% of current coal consumption out of the Northern Great Plains.

The model has three principle components (Figure 8): a spatial market model, an electric forecasting model, and an interfuel substitution algorithm. In the original model, the spatial analysis concerned Powder River coal versus seven competing coal supply centers in Illinois, Texas, New Mexico, southwest Wyoming, Utah and Washington. A Powder River supply center at Gillette was used to represent both Montana and Wyoming Powder River coals. The current analysis requires an additional market boundary delineation--between Montana and Wyoming coals. The new Montana supply center is located at Forsyth, with the Wyoming supply center at Bridger Jct. The programming for the modified computer model for generating new hyperbolic market boundaries (NEWHYP) is provided in Appendix A. The basic purpose of the spatial model is to identify the geographical areas where Montana and Wyoming coals are least cost against

Figure 8

Forecasting coal demand in the western United States



competing fuels. Assuming that electric utilities are well-informed and that utilities are cost-minimizers, the model will have identified the spatial coal markets for Montana and Wyoming coals, respectively. The basis of the cost comparison is not simply current $/ton or cents/MBTU delivered, but is instead based on the estimated present value of all coal-related costs to a given utility over the life of a given plant. These costs include variations in coal-fired plant construction and operating expenses as a function of coal rank (BTU content) and quality (sulfur, ash). The latter are in turn a function of the flue-gas desulfurization standards assumed to be in effect. In addition, the present value calculation requires specification of a discount rate and escalation rates for each of the key cost components (e.g. transportation, etc.). The original data base is described in considerable detail in Duffield et al, 1982.

Once the spatial market is identified, it is necesssary to forecast the growth of electric consumption in the market area. Since the demand for Powder River coal is largely derived from the demand for electricity, coal production is closely tied to the growth rate of electric generation in the market area. An econometric state-level forecasting model developed at the Oak Ridge National Laboratory has been adapted to forecast electric consumption in the market area. Consumption in states bisected by the market boundary is allocated to competing coals on the basis of the grid location of population centers vis-a-vis the boundary The electric forecast is driven by exogenous population, income and price scenarios. An alternative approach is to use the rates of growth currently being forecast at the state and regional level by other analysts (e.g. the U.S. Department of Energy, the National Electric Reliability Council [NERC], etc.).

The final component of the overall model is an interfuel substitution algorithm for allocating electric production capacity among competing fuels (coal, oil, gas, nuclear and hydro). The latter is simplified by long construction lead times and known commitments to nuclear facilities. The overall model is relatively simple, robust and low cost compared to the linear programming approach taken in the large national coal models. Nonetheless, model predictions have been found to be consistent with the pattern of change in current and contracted coal deliveries in the region. Future levels of coal production from the NGP will be closely tied to real increases in mining labor costs, rail transportation, and the growth rate in electrical consumption. The other key factors will be federal policy for sulfur dioxide air pollution control, transportation regulation, fuel switching, and federal subsidy and regulation of nuclear and synthetic fuel plants. The scale, timing and location of development is also closely tied to federal reclamation and leasing policy.

It is beyond the scope of this paper to provide a complete discussion of the basic model. The interested reader is referred to Duffield _et al_ (1982). In the following section, the spatial market model is briefly described. The schematic in Figure 8 provides an overview of the basic model components, information flows, and key policy inputs.

Spatial Market Model

Commodities which have a low value to weight ration, such as coal or cement, have a fairly well-defined geographical market. The basic theory of spatial markets is due to Hyson and Hyson (1950) and has been previously applied to model coal markets by Watson (1972), Silverman _et al_ (1976) and Campbell and Hwang (1978). The work described here is an extension of the applications by Watson and Silverman, which were limited to two competing coal sources. Campbell and Hwang's paper provides a solution for multiple sources

and quadratic transportation functions, but did not account for the critical differences in coal qualities (especially sulfur content).

The spatial market boundary is defined by the following equilibrium relationship:

(1) $M_1+T_1D_1=M_2+T_2D_2$ or solving for D_2:

(2) $D_2=(M_2-M_1)/T_2 + T_1D_1/T_2$ or

(3) $D_2=k+hD_1$ where:

M_1 is the mine mouth (FOB) price of coal 1

T_1 is the variable cost of transportation

D_1 is the distance from mine 1 to the market boundary

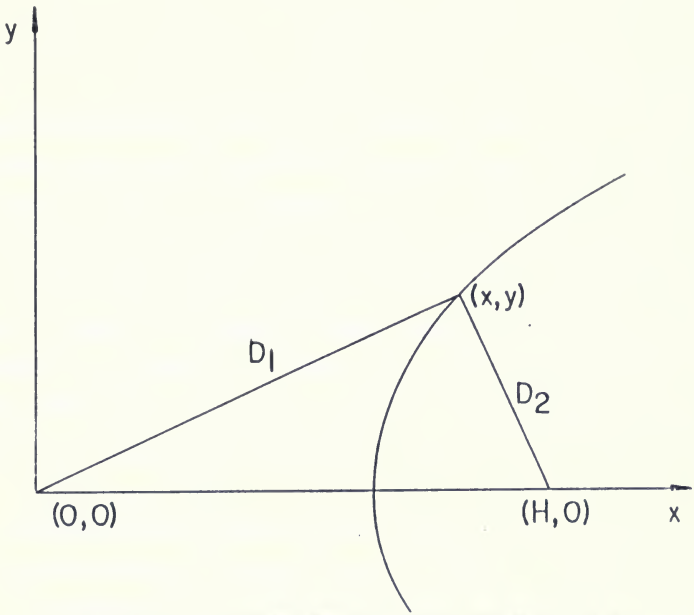
In short, the spatial market boundary between two competing coals is defined as the loci of points where the delivered prices are equal. To one side or the other, a given producer has a cost advantage and dominates the market. Application assumes that buyers are cost minimizers, that producing areas may be approximated by point sources, that a fairly uniform transportation network exists, and that coal prices may be taken as exogenous. The latter can yield good approximation of reality here as current market structure in the mining areas, and the very vast scale of reserves, imply quite elastic supply curves. In any case, the forecasting model can be used to increment mine mouth prices and transportation rates in any given year.

A solution to the relationship in Eqs. 1-3 requires the introduction of a spatial constraint. For example, using a rectangular coordinate system (Figure 9) with H defined as the distance between competing centers and applying the Euclidian distance function, Eq. 3 becomes:

(4) $(H-x)^2+y^2=k^2+2hk(x^2+y^2)^{1/2}+h^2(x^2+y^2)$

The solutions to this quartic polynomial yield the loci of market boundary points. Solutions to Eq. (4) were originally investigated by DesCartes as a

Figure 9



Rectangular Coordinate System for Spatial Market Analysis.

problem in optics and are known as DesCartes' ovals. It can be shown that when the T_1 are equal, the boundary is a hyperbola and when the M_1 are equal it is a circle. The general case yields roughly eliptical curves. In application, Eq. (4) is first solved for the point on the straight line between market centers (y=0). Then y can be iterated to solve for additional points. Boundaries vis-a-vis more than one center are identified by rotation of the axis.

The application to coal entails defining the mine mouth price to include all distance independent costs of burning a given coal, then:

(5) $$M_1=(CP_1+FTC_1)TONS_1+KCOST_1FCR_1+OM_1T_1$$

$$T_1=VTC_1TONS_1$$

$$TONS_1=t_1HR_1/HC_12000$$ where:

CP_1 is the mine mouth price of coal 1

FTC_1 is the fixed transportation cost of coal 1

$TONS_1$ is the total tons of coal 1 required to utilize a unit of generating plant capacity (kilowatt) for one year

$KCOST_1$ is the generating plant capital cost associated with coal 1 (desulfurization equipment, oversize boilers, etc.)

FCR_1 is the fixed charge rate used to annualize capital expenditures OM_1 is the operation and maintenance charge specific to coal 1 (mainly pollution control equipment)

VTC_1 is the variable cost per ton-mile of transportation

t_1 is the hours per year that the tenerating plant is anticipated to operate

HR_1 is the heat rate at which coal BTU's are converted to kilowatt hours of energy by the generating plant

HC_1 is the heat content of coal 1 in BTU's per pound

The model was previously applied to seven major supply centers that compete with NGP coal: the Eastern Interior Basin (Illinois), Texas lignites, Washington (Centralia), Utah (Uinta Basin), New Mexico (San Juan Basin), Colorado, and southern Wyoming (Green River/Hams Fork). In general, NGP coal is lower BTU content (8500 BTU/lb average versus 11,000 to 12,000 for Interior and Utah coals), lower sulfur (0.6% for most western coals versus 3% and up for Illinois), and lower cost ($8 to $12 per ton versus around $20 per ton FOB for most of the other coals.)

A major determinant of the boundary location is the relative cost of meeting sulfur emission standards. The shipment of substantial amounts of NGP coal beginning in the 1970's was closely tied to the federal New Source Performance Standards (NSPS) that came into effect in 1971 and required that all new coal fired generating plants meet an emission standard of 1.2 lbs of sulfur per million BTU of fuel input. Some NGP coal was able to meet this standard with no flue gas desulfurization (or scrubbing) and therefore had a considerable cost advantage over high sulfur coals. However, the standards were revised in 1978 and the RNSPS in effect require 90% control on high sulfur coals and 70% control on low sulfur. This change increases the cost of using NGP coal and was in part brought about by the political power of the midwestern coal lobby that was attempting to protect its market from western coals.

The parameters required for an application of the spatial component of the model and forecast results for Montana versus Wyoming coals are presented below.

Data and Parameters

The basic data requirements for each boundary in a spatial market model run are listed in Figure 10. The actual data input files and spatial maps

Figure 10

Variable Description for Market Boundary Parameters*

Line #	Coal Supply Center	Variable Description
1	A & B	Power plant size (net MW)
2	A & B	Hours operated at full load (hours)
3	A	Power plant heat rate (BTU/KWhr)
4	A	Coal heat content (BTU/lb)
5	B	Power plant heat rate (BTU/KWhr)
6	B	Coal heat content (BTU/lb)
7	A	Power plant capital cost ($/KW)
8	B	Power plant capital cost ($/KW)
9	A & B	Fixed charge rate (decimal)
10	A	Operating and maintenance costs ($/KWhr)
11	B	Operating and maintenance cots ($/KWhr)
12	A	FOB mine price ($/ton)
13	B	FOB mine price ($/ton)
14	A	Fixed transportation cost ($/ton)
15	B	Fixed transportation cost ($/ton)
16	A	Variable transportation costs ($/ton-air mile)
17	B	Variable transportation costs ($/ton-air mile)
18	A & B	Straight line distance between A & B (miles)

*Duffield, Silverman (1982) p. 8-55

(discussed below) are provided in Appendix C. Many of the parameters are based in part on the original documentation (Duffield et al, 1982); since the latter runs to over 600 pages, only a brief summary of key parameters and updates will be provided here. Each column in Appendix C Tables corresponds to a boundary.

Each of the key parameters will be discussed briefly below:

1. Size:

The model plant for the current study was assigned a size of 500 MW. This was based on a survey of net capacity of utility boilers in Duffield, Silverman (1982), where the average net capacity equaled 500 MW.

2. Capacity Factor:

A 65% average capacity factor was assumed which results in 5694 operating hours per year. This average capacity factor was based on Duffield, Silverman (1982).

3. Heat Rates:

The heat rates for the 1984 study were based on the heat rates developed in Duffield, Silverman (1982). This was corroborated in a phone discussion with a member of ICF, where the original information was developed. Montana's model plant was assumed to be the same as the Powder River, Wyoming plant.

4. Power Plant Capital Costs:

These are based on costs developed in Duffield, Silverman (1982). PPCC w/o sulfur control costs were escalated to 1984 dollars at a real rate of 2.3%. The sulfur control costs were escalated to 1984 dollars at a real rate of 0.5%. After multiplying the PPCC w/o by a capacity penalty, the two costs are added together in order to get total power plant capital costs. These costs are levelized within the model when multiplied by the fixed capital recovery factor. In addition to accounting for real changes, all inputs were

converted from mid-1980 dollars to mid-1984 dollars by the Implicit Price Deflator (IPD) for GNP.

5. Fixed Capital Recovery Factor:

The FCRF in 1984 was assumed to be the same as in 1982, based on Duffield and Silverman (1982).

6. Operation and Maintenance Costs:

These are based on costs developed in Duffield, Silverman (1982). 1982 operating and maintenance costs without sulfur are escalated to 1984 dollars at a real escalation rate of 1.2%. The additional operation and maintenance costs for sulfur control was also escalated at a real rate of 1.2%. These two costs are added together to determine total 1984 operation and maintenance costs. (See tables 6, 7, 9 pp. 8-14:8-17, Duffield, Silverman, 1982) Montana operation and maintenance costs were assumed to be the same as Wyoming Powder River power plants.

7. FOB Mine Prices:

Because FOB mine prices on a contract basis are confidential, a number of alternative price sources were investigated as summarized in Table 13. One source for Montana coal FOB prices are a weighted average based on the mine specific reports on the Gross Proceeds Tax form for 1983. The Decker and Spring Creek mines produce coal that is somewhat higher BTU content (Decker averages 9600 BTU) than the other three subbituminous producers (Westmoreland, Western Energy and Peabody averaging around 8400 to 8700 BTU/lb). The latter three mines produce coal more similar to the average Wyoming Powder River coals centered around Gillette. The average FOB for the three mines in 1983 varied from 10.77 to 11.13 and averaged $11.01/ton.

By contrast, the Decker coal sells at a much higher average price of $19.31 in 1983. (Spring Creek is intermediate at $15.96.) The price premium

Table 13

Comparison of FOB Prices

Montana and Wyoming

Source	Montana		Wyoming	
	BTU	$/ton	BTU	$/ton
A. State Tax Records for 1983:				
	8700	10.77	8450	9.77
		11.13		
		10.90		
	9300	15.96		
	9600	19.31		
B. New Contract Information:				
	8700	9.50	8450	7.70
C. Coal Week - New Contracts 1984:				
	8600	9.75	8100	6.25
	9300	12.00		

reflects the higher BTU and low sulfur qualities of Decker coal. Based on an analysis of mine-utility specific deliveries for 1984 (U.S. Department of Energy tape of Form 423) Decker and the south Wyoming mines (Black Butte, Carbon County, etc.) appear to be competing in a somewhat separate market from the more typical lower BTU Montana and Wyoming PowderRiver coals.

The FOB mine price for Wyoming coal is more difficult to obtain since it is reported only on a confidential form. Only "value per ton" is reported by the Wyoming Department of Revenue. However, individuals in the Wyoming Ad Valorum Tax Division were able to supply us with an average for Powder River Basin mines of $9.77 for 1983.

Prices based on state tax records are probably the best source for current average price. However, this average includes prices based on contracts that were signed 10-15 years ago. For purposes of our model, it is necessary to know what current prices are for new contracts. One source for such estimates is Coal Week. Based on the latter, Wyoming producers are bidding new contracts at an average of 6.25$/ton. This is $3.50 below the existing contract average of $9.77 in 1983. Another estimate for Wyoming new contracts from individuals at the Wyoming Geological Survey is $7.70. The Coal Week $6.25 may be low for an average, but is close to the $6 estimate derived for the Rochelle Mine's Minneapolis deliveries as discussed above.

The current distribution of Wyoming Powder River prices was also summarized in Figure 7 above and briefly discussed. The distribution in Figure 7 is based on a set of estimated prices for Powder River Coal published in Coal Transportation Report (February 20, 1984). Figure 5 is a frequency plot of 20 useable observations (early 1984 prices) on Wyoming Powder River mines. The most interesting finding is that the distribution is bimodal at about $6.50 and

$12. This reflects perhaps the most important recent coal market development in the Powder River, which is price cutting by some of the large Wyoming producers. As an example, it was recently reported on the Wyoming Quarterly Update (summer 1984) that Omaha Public Power has renegotiated a coal supply price with Exxon (Caballo and Rawhide mines) that resulted in a drop in FOB mine price from $8.25/ton to $5.75/ton. Our preliminary analysis of delivered July 1984 prices based on Form 423 and BN tariffs disclosed a number of what appear to be long term contracts delivered on the order of $6 to $7/ton.

For Wyoming prices on average, it appears that market forces have lowered new coal contract prices by several dollars. While 7.70 $/ton may be the best available average, for our modeling we have also done a number of estimates at $6/ton, given the possible significance of these low bids for the Minnesota market.

Based on Coal Week and the contract estimate derived above for the Sherco #3 analysis, Montana coal producers have also lowered contract bids. The estimated reduction is $1.25 to $1.50 for 9.50 to 9.75 $/ton for 8700 BTU coal. Spring Creek type coal is down considerably, $4, to $12/ton from the contract average. For purposes of our analysis, we have taken 9.50 as a base estimate for 8700 BTU Montana coal and $12 to $12.50 for 9300 to 9600 BTU coal. However, it should be noted that unlike the Wyoming prices, there is not much market evidence on whether these are the most appropriate estimates. Particularly for Decker type coal, with an average FOB in 1983 of 19.31, if the Coal Week estimates are correct at least some Montana producers have considerable room for price adjustments. It is impossible to address these questions without analysis of mine specific production costs. The latter is important but beyond the scope of this analysis.

9. Transportation Rates:

For most coal shipments out of the Powder River the dominant cost component in delivered price is transportation. In 1980 the fixed and variable cost components for NGP shipments were \$1.04/ton and \$.0113/ton-mile respectively based on a study by ICF, Inc. In order to estimate current rates, the complete set of burlington Northern (BN) time-volume/unit train tariffs as of July 1984 was obtained for Wyoming and Montana coal shipments. Based on regression analysis of 120 observations, the following linear equation was specified:

$$\underset{\text{(t-statistic)}}{\text{TARIFF}} = \underset{(2.67)}{1.77} + \underset{(27.80)}{.0166}\ \text{MILE}$$

The overall adjusted R-square was .88, indicating an excellent fit to the data. When "minimum volume" was included as a second independent variable, the estimated coefficient was not significantly different from zero. The estimates above are, of course, in mid-1984 dollars. This indicates a yearly nominal change in rail tariffs of 9.2% or (given the change in the IDP mid-80 to mid-84) 3.4% annual real increase. This is very close to the historical 3.5% change (15 year basis) as well and the escalation rate used for levelizing rail transport in our 1982 study. However, our preliminary analysis of the 1983 and 1984 unit train rate changes indicate a possible slowing of rate increases to perhaps 1% real per year. The latter was used in Tables 1 to 4 to derive levelized rail rates for 1984. For example, the first year variable cost per ton mile is estimated to be .0166 in 1984. Levelized over 30 years at 1% per year and a real weighted cost of capital of 3.77% yields a levelized variable cost of .0189 per rail mile. Since our model is run on actual (air mile) rectangular coordinates, this is inflated by the rail/air mile ratio for each boundary (e.g. 1.30 for most locations or .0246 as in Appendix C Tables).

In order to account for the substantial additional distance Wyoming coal must travel to the major Montana low-BTU market in Minnesota, fixed transportation cost equivalent to an extra 200 miles was included in the Wyoming transportation cost function. Similarly in modeling states just south of the Minnesota and Wisconsin borders, the difference in air to actual miles from the market centers required an 80 air mile addition to Wyoming fixed costs.

10. Contract Data:

Existing contracts for Wyoming (Powder River only) and Montana coals are summarized in Appendix B. This data is derived from a listing purchased from Coal Network Associates, Inc. and is difficult to verify. In particular, it appears that deliveries from all states to a given plant are occasionally averaged to yield the $/ton figures listed.

11. Reclamation Costs:

Reclamation costs in the Powder River Basin are truly site specific. Although state/federal rules and guidelines applied in the individual states offer minor differences between Montana and Wyoming, cost differences are clearly most sensitive to overburden ratios, coal seam thickness, quality of the overburden (acceptability as a growing medium) and the amount of heavy earth moving as a function of mine design. In general, for Powder River Basin area mines, earth moving costs will range from one-third to one-half total reclamation costs. Revegetation costs will average 10% to 15% of total costs, and depending upon the site, reclamation cost can range from a low of $.25 per ton (est.) to a high of perhaps $1.00 per ton (est.). High and low range can be found in both Montana and Wyoming. Because of the variation in costs in both states, resulting in some possible Montana reclamation costs being

slightly higher or lower than Wyoming costs it is impossible to generalize about the cost impact of mining regulations in both states. Suffice it to say that on a delivered BTU basis, the cost of reclamation is very small, perhaps averaging 2.0 to 2.5 cents per million BTU out of a delivered price of $1.40 to $1.60 per million BTU.

A model for reclamation costs in the Powder River Basin is the Rosebud Mine of Western Energy at Colstrip, Montana. Costs at this mine, shown below, probably reach the average for mines in the region, or slightly above the average. Big Sky Mine of Peabody Coal will probably have somewhat higher costs per ton, while Decker costs are probably somewhat lower. In Wyoming, most reclamation costs are somewhat lower than Rosebud due to thicker seams, lower overburden and perhaps more stringent permitting requirements, although the latter is not fully documented as yet.

In any case, reclamation costs at Rosebud, on a per acre basis averages just under $18,000, divided among Associated Level ($600.00/AC), Facilities Level ($5,800.00/AC) and Mining Level ($11,500.00/AC) components. Based upon an average seam thickness of 25 feet and a production of 45,000 tons per acre, these values give a reclamation cost of $0.40 per ton at Rosebud, or about 2 cents per million BTU.

One note about reclamation costs; neither in Montana nor Wyoming has a reclamation bond been released and reclamation certified as complete or accomplished. This is an important point; total reclamation has not been demonstrated at any mine site in either state, and estimated costs of reclamation as calculated in bonding requirements may in fact be slightly low. However, it is not expected that future reclamation requirements would double current estimates.

Table 14

Revised Status of Reclamation Bonding,

Rosebud Mine

Bond Level/ Cost Element	Operating Cost/Acre	Ownership Escalation	Net O&O Cost/Acre
Associated Level			
Revegetation	$ 480	1.22	$ 585
Facilities Level			
Scoria Removal	$ 2,400	-	$ 2,400
Regrading	$ 495	1.22	$ 605
Soil Redistribution	$ 1,800	1.22	$ 2,195
Revegetation	$ 540	1.22	$ 660
			$ 5,860
Mining Level			
Regrading	$ 2,244	1.22	$ 2,740
Soil Redistribution	$ 1,224	1.22	$ 1,495
Revegetation	$ 425	1.22	$ 520
Final Pit Reclamation	$ 6,816	-	$ 6,815
			$11,570

Source: Western Energy Co., December 1983

D. Montana Coal Production Forecast

The coal production forecast described in this section is based on the data inputs and spatial model described earlier. The Montana coal modeled is 8700 BTU coal. As developed in Appendix D, Decker 9600 BTU coal at $19.00/ton is clearly out of the RNSPS new plant market. The modeling choice of 8700 BTU coal is based on uncertainties about new Decker contract prices and apparent market dominance by 8700 BTU coal, even at somewhat lower prices for Decker type coal.

The basic analysis performed here was to estimate the spatial market for Montana coal against $6.00 and $7.70 Wyoming 8450 BTU coal. The focus is on identifying how the Montana market changes as Montana FOB price changes in $1 steps from $10.50 to $6.50 with $9.50 the base case. Specific data inputs and corresponding spatial market maps are described in Appendix C. The results are summarized in Tables 15 and 16, which show the population-weighted percent of each state lying within the Montana coal market for the ten specific price combinations.

Consistent with the specific discussion of the Minneapolis deliveries above, Minnesota is in the Montana coal market against $6 Wyoming coal even at $10.50 (Table 15). As the price drops to $9.50, the market expands in the northwest (NW) into Washington and Idaho and in the northcentral (NC) to include Wisconsin and part of Michigan. At $8.50 all of Michigan and Idaho are included and at $7.50 most of Oregon. At $6.50 parts of northern Illinois, Indiana, and Iowa are in the market. The market picture against $7.70 Wyoming coal is similar except that at lower prices the Montana coal market extends further south into Iowa, Illinois, and Indiana. When the Montana price is substantially below the Wyoming price (6.50 Montana vs. 7.70 Wyoming), the market even includes Nebraska and parts of Missouri. In the NW further market

Table 15

MONTANA COAL MARKET
POPULATION % SUMMARY
AGAINST 6.00 WYOMING FOB

State	Montana FOB				
	10.50	9.50	8.50	7.50	6.50
Montana	1.00	1.00	1.00	1.00	1.00
Washington	.10	.80	.80	.91	.96
Oregon	.09	.09	.09	.84	1.00
Idaho	.19	.64	1.00	1.00	1.00
Minnesota	.96	1.00	1.00	1.00	1.00
Wisconsin	.17	1.00	1.00	1.00	1.00
Michigan	0.0	.38	1.00	1.00	1.00
Iowa	0.0	0.0	0.0	0.0	.22
Illinois	0.0	0.0	0.0	0.0	.80
Indiana	0.0	0.0	0.0	0.0	.38
Nebraska	0.0	0.0	0.0	0.0	0.0
Missouri	0.0	0.0	0.0	0.0	0.0

Table 16

MONTANA COAL MARKET
POPULATION % SUMMARY
AGAINST 7.70 WYOMING FOB

State	Montana FOB				
	10.50	9.50	8.50	7.50	6.50
Montana	1.00	1.00	1.00	1.00	1.00
Washington	.10	.80	.80	.91	.96
Oregon	.09	.09	.09	.84	1.00
Idaho	.37	.75	1.00	1.00	1.00
Minnesota	1.00	1.00	1.00	1.00	1.00
Wisconsin	1.00	1.00	1.00	1.00	1.00
Michigan	.35	.38	1.00	1.00	1.00
Iowa	0.0	0.0	.09	.92	1.00
Illinois	0.0	0.0	.03	.90	1.00
Indiana	0.0	0.0	.04	.44	.86
Nebraska	0.0	0.0	0.0	.02	1.00
Missouri	0.0	0.0	0.0	0.0	.58

extension is precluded by proximity to Utah and south Wyoming coal centers. In fact the extent of the market in the NW may be somewhat overstated given the likelihood of minemouth generation in south Wyoming with transmission by wire to southern Idaho and Oregon. We have excluded both North and South Dakota from the market area based on historic and projected minemouth lignite plants.

Incremental demand for coal is each state (or portion of a state) in the market area was estimated for 1990, 1995 and 2000 at 1%, 2%, and 3% electric growth rates. After total electric generation was calculated for a given state (for a specific year and growth rate) projected and existing generation due to hydro, nuclear, oil and gas and existing coal was subtracted to get the residual electric generation needs to be met by new coal-fired plants. This residual generation was then converted into coal demand in million tons per year. The results of this calculation summed over all states is provided in Table 17 for each of the ten spatial market cases.

The results in Table 17 are consistent with known coal-fired capacity additions to 1990 and 1993 (for example, Table 12). Utility plans as reported to NERC were used as an upper limit to incremental coal demand in the 1990 forecasts and in 1995 for growth rates of 1% and 2%. As a result, the projections in Table 17 are more realistic but have some resulting discontinuities. For example, in 1990 the 3% case is not very different than the 2%. This is because utilities are not planning for 3% growth and if such occurred, unexpected growth could not be met with coal given the lead time on new plant construction. This constraint also limits 1% and 2% growth in 1995, but 3% is unconstrained and is substantially higher.

The results in Table 17 also incorporate the Northwest Power Planning Council's expected impact on the mix of new electric generation and

Table 17

Montana Coal Production
Forecast (million tons per year)

Year:		1990			1995			2000		
Electric Growth Rate:		1%	2%	3%	1%	2%	3%	1%	2%	3%
A. Wyoming FOB Price $6 Montana FOB ($/ton)										
10.50		36.4	38.4	41.3	38.0	44.2	53.0	44.1	51.0	59.9
9.50	BASE	38.1	41.5	42.9	41.9	46.2	64.6	48.3	62.9	85.2
8.50		38.9	42.5	44.2	42.8	47.2	72.2	48.3	68.0	96.8
7.50		42.7	44.7	44.7	45.4	47.2	72.2	48.3	68.0	100.1
6.50		42.7	44.9	45.9	45.6	49.1	76.9	48.7	72.2	118.1
B. Wyoming FOB Price $7.70 Montana FOB										
10.50		37.9	40.8	42.0	41.3	45.3	64.6	48.3	62.9	81.2
9.50	BASE	38.6	41.8	43.3	42.5	46.3	64.6	48.3	62.9	85.4
8.50		38.9	42.5	44.2	42.8	47.2	73.0	48.4	68.7	98.4
7.50		42.7	45.6	46.0	46.0	50.2	80.8	49.8	75.8	125.0
6.50		42.7	45.8	47.4	46.6	54.4	94.7	50.8	89.8	140.8

conservation resources in the northwest. For example, our model predicts a need for 4900 average mw of new resources in the NW at 2% electric growth and in the year 2000. If this was to be met with new coal-fired capacity, this would imply an additional 26 mtpy of coal demand. However, the Power Planning Council is expecting to meet this incremental load (if it occurs) with about 4000 average mw of conservation plus about 900 mw combustion turbines and cogeneration. Only for the Council's highest growth case (2.9%) is there any new coal-fired capacity in the NW even by the year 2000. The Council's estimate is for approximately 1900 mw or 10 mtpy of new coal demand in the high growth case. This contrasts with the approximate 48 mtpy our model would assign at 3% growth in the absence of this information. Given that we have not been able to quantify the effects of major state or regional level conservation efforts in the remainder of the Montana market area, the estimates in Table 17 should be taken as an upper limit.

It is also worth noting here that both the Power Planning Council and BPA are projecting NW regional growth at around 1.6% to 2000. The Council's high case of 2.9% growth is a very high "high" based on extreme demographic and economic assumptions. The Council expects that there is only a 22% chance of growth in excess of 2.3%, but a 33% chance that it could range from 1.7% to .8%. By contrast, the NERC projection for the NWPP (which also includes Utah) for 1983-1993 is for 2.5%. This supports the interpretation of the NERC projections as a reasonable upper limit. The U.S. Government's Energy Information Administration is forecasting 4.1% for 1984-1995 for the NW and Alaska. This seems quite unrealistic. In short, it appears that carefully developed regional forecasts comparable to those for the PNW are not available for other regions. In interpretations of Table 17, 2% growth may well be a reasonable base case. At 2% growth and for a base case Montana FOB price of 9.50, a likely production

forecast for Montana is 42 mtpy in 1990, 46 in 1995 and 63 in 2000. Coal production levels are quite sensitive to the annual rate of growth in electric sales. For example, the year 2000 base case forecast is 48 mtpy at 1% electric sales growth but almost double or 85 mtpy at 3%. The 1984-2000 average annual growth rate for base case coal production corresponding to 1%, 2%, and 3% compound growth in the electric sector are 2.5%, 4.3% and 6.2% respectively.

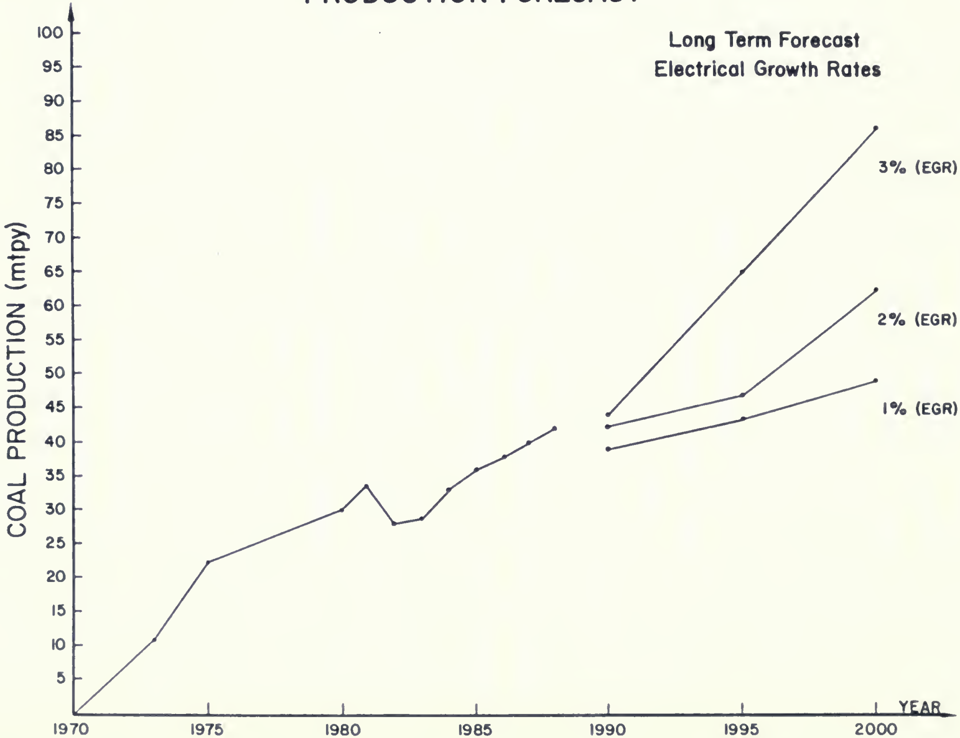
The various base case projections are summarized in Figure 11 along with historical production and the short term forecast. The 1990 forecast range of 38.6 mtpy to 43.3 mtpy is consistent with the mine survey-based forecast developed by the Montana Governor's office of 41.6 mtpy in 1988. The latter shows the expected growth over 1984 production due to Colstrip 3 and 4 and Belle River #2 plus movement toward contract maximums as capacity factors improve on existing units. It should be noted that even with no changes in contracts, there can be considerable swings in production levels within contract minimums and maximums. For example, Colstrip 3 and 4 operated at 40% capacity require about 3 mtpy and at 80%, 6 mtpy. These in fact correspond to the contract minimum and maximum on these units. The production swing within existing contracts just for Montana Power Company plants is about 4.7 mtpy and including other Western Energy contracts is at least 8.4 mtpy. In short, the range forecast for 1990 as a function of electrical growth rates (which impact capacity factors) is quite plausible and consistent with the short term forecast.

A final comment on the base forecast is that it assumes all existing contracts will be renewed as they expire to 2000. The major contracts that are due to expire in the mid-90's are all in Minnesota and Wisconsin. These states are in the market area for the Base Case of $9.50 and it would appear very likely that these contracts would be renewed.* In 1997, 1998, and 1999

*See Appendix F.

Figure II

MONTANA COAL PRODUCTION FORECAST



some Decker contracts with Commonwealth Edison in Illinois and Detroit Edison in Michigan expire. The potential for renewal of these contracts has not been closely investigated. Given the uncertainties of Decker prices, the special market (high BTU, low sulfur, older plants) involved, and the relative distance of the event in time, we have assumed that these contracts will be renewed for the year 2000 forecast.

E. Incremental Coal Production Forecast

The incremental or new coal production in Montana that could be expected for each of the ten spatial market cases is summarized in Table 18. This is derived from Table 17 by subtracting expected 1984 production of 32.3 mtpy. The discontinuities in Table 18 are again partly related to real constraints imposed by utility planned coal additions. Also, while it is clear from Tables 15 and 16 that the market expands for every price reduction, in some cases the state or portion of a state added will not be needing new coal-fired capacity at the growth rate and year indicated. For example, there is 7466 mw of nuclear capacity that is coming on line in Illinois in the next few years. Because of this legacy from days of expected higher electric growth, there is no need for new coal-fired capacity in Illinois even at 3% to the year 2000. Similarly, there will be no new coal-fired capacity in Michigan unless growth exceeds 2%.

The effect of a $1/ton price reduction at initial prices of 10.50, 9.50, 8.50, and 7.50 are summarized in Table 19 (again derived from Table 17). Again, the discontinuities here are due to the real constraints on new coal capacity expansion plus utility-specific planning for substitute resources: nuclear, oil and gas, hydro, and conservation. Given those discontinuities and the uncertainties about base prices, a better picture of the effect of a

Table 18

Incremental Coal Production
Forecast for Montana over
1984 Base (million tons per year)

Year:		1990			1995			2000		
Electric Growth Rate:		1%	2%	3%	1%	2%	3%	1%	2%	3%
A. Wyoming FOB Price $6										
Montana FOB ($/ton)										
10.50		4.1	6.1	9.0	5.7	11.9	20.7	12.0	18.7	27.6
9.50	BASE	5.8	9.2	10.6	9.6	13.9	32.3	16.0	30.6	52.9
8.50		6.6	10.2	11.9	10.5	14.9	39.9	16.0	35.7	64.5
7.50		10.4	12.4	12.4	13.1	14.9	39.9	16.0	35.7	67.8
6.50		10.4	12.6	13.6	13.3	16.8	44.6	16.4	39.9	85.8
B. Wyoming FOB Price $7.70										
Montana FOB										
10.50		5.6	8.5	9.7	9.0	13.0	32.3	16.0	30.6	48.9
9.50	BASE	6.3	9.5	11.0	10.2	14.3	32.3	16.0	30.6	53.1
8.50		6.6	10/2	11.9	10.5	14.9	40.7	16.1	36.4	66.1
7.50		10.4	13.3	13.7	13.7	17.9	48.5	17.5	43.5	92.7
6.50		10.4	13.5	15.1	14.3	22.1	62.4	18.5	57.5	108.5

Table 19

Effect of a $1/ton Reduction
on Montana Coal Production
(million tons per year)

Year:	1990			1995			2000		
Electric Growth Rate:	1%	2%	3%	1%	2%	3%	1%	2%	3%
A. Wyoming FOB Price $6									
Initial Montana FOB									
10.50	1.7	3.1	1.6	3.9	2.0	11.6	4.0	11.9	25.3
9.50	.8	1.0	1.3	.9	1.0	7.6	0.0	5.1	11.6
8.50	3.8	2.2	.5	2.6	0.0	0.0	0.0	0.0	3.3
7.50	0.0	0.0	1.2	.2	1.9	4.7	0.0	4.2	18.0
B. Wyoming FOB Price $7.70									
Initial Montana FOB									
10.50	.7	1.0	1.3	1.2	1.3	0.0	0.0	0.0	4.2
9.50	.3	.7	.9	.3	.6	8.4	.1	5.8	13.0
8.50	3.8	3.1	1.8	3.2	3.0	7.8	1.4	7.1	26.6
7.50	0.0	.2	1.4	.6	4.2	13.9	1.0	14.0	15.8

$1 reduction may be obtained by averaging the $9.50 and $10.50 Montana FOB prices and the $6.00 and $7.70 Wyoming FOB cases. The results are summarized in Table 20.

The effect of a $1 price reduction in 1990 and 1995 is to increase projected prodution by about 1 mtpy at all electric growth rates except 3% in 1995 where it is 7 mtpy. In 2000, a $1 reduction increases production by 1, 6, and 14 mtpy for 1%, 2% and 3% growth respectively (Table 20). The long-run elasticity of demand in the year 2000 corresponding to the three growth rates are -.2, -.9, and -1.6. These are within the range one would expect given general findings on the price-elasticity of demand for energy.

F. Comparison to Other Studies

We are aware of two other recent long-run estimates of the market for Montana coal. One is a study by Victor Wood entitled Montana Coal Market Study. An 18 page draft dated July 3, 1984, was made available to us through the Montana International Trade Commission. Wood does not provide much discussion of his method, but his key input assumptions: Montana base price of $9.75 for 8600 BTU coal and $13 for 9600, Wyoming at $7.50 and 8300 BTU, and rail at 2.0¢ to 2.2¢ in per ton-mile for western movements are similar to ours. He provides a coal production estimate based on the NERC overall utility load growth of 2.3% annually.

His spatial market estimate is also similar to ours except that he expects the Montana coal market would penetrate well into Missouri, Oklahoma, and Arkansas even for a $2 reduction. He is in apparent agreement that for the base case Minneapolis and most of Minnesota and Wisconsin are well within the market. He does not, however, expect any sensitivity of his market boundary in the NW (roughly, the Oregon-Washington border plus northern Idaho) to price reductions.

Table 20

SUMMARY

Base Case Montana Coal Production Forecast
(million tons per year)

Year:	1990			1995			2000		
Electric Growth Rate:	1%	2%	3%	1%	2%	3%	1%	2%	3%
Total Production	38	42	43	42	46	65	48	63	85
New Production	6	9	11	10	14	32	16	31	53
[a]Increase for $1/ton Price Reduction	.9	1.5	1.3	1.6	1.2	6.9	1.0	5.7	13.5

Note: [a]Increase is based on average of 9.50 and 10.50 Montana FOB and 6.00, 7.70 Wyoming FOB cases.

Wood's forecast at 2.3% electric growth is compared to our most similar ($9.50 Montana and $7.70 Wyoming base) case at 2% and 3% in Table 21. His forecast for 1990 at 2.3% is 3 to 4 mtpy new coal production, which is below both our 2% and 3% forecast by 7 to 11 mtpy. In 1995 his estimates are consistantly bracketed by ours and we appear to be in substantial agreement. However, in 2000 his numbers look high, with his 2.3% estimates very similar to ours for 3% growth. Wood's estimate of the production response to a $1/ton reduction is zero in 1990, +1 in 1995, and +7 mtpy in 2000. This is similar to our 1.5, 1.2, and 5.7 mtpy increases for 1990, 1995, and 2000 at 2% electric growth.

Without more information on Wood's method it is difficult to explain the differences. Perhaps the main point here is that the results are fairly similar. Both studies show substantial growth in Montana coal production even without price reductions. (Wood's forecast implies 5.8% annual growth 1984 to 2000). Both studies also show similar response to price reductions.

By contrast the only other long-run estimate we have seen was presented by Martin White of Western Energy in a recent interview reported in the Billings Tribune. White predicted a steady decline in coal sales from a peak of 33.3 mtpy in 1986 to 20.9 in 1995 at current price (and coal severance tax) levels. This forecast is apparently predicated on the loss of all existing contracts as they come up for renewal. In addition, it appears to preclude any new production related to plants coming on line between 1984 and 1995, including Colstrip 4 and Belle River #2. Based on the present analysis and the study by Victor Wood, there appears to be little basis for White's projection.

Table 21

Comparison of Incremental Coal Production Forecasts for Montana (million tons per year)

Year:	1990			1995			2000		
Electric Growth Rate:	2%	2.3% (Wood)	3%	2%	2.3% (Wood)	3%	2%	2.3% (Wood)	3%
Base Condition	10	3	11	14	21	32	31	50	53
$1/ton Reduction	10	3	12	15	22	41	36	57	66
$2/ton Reduction	13	4	14	18	32	49	44	88	93
$3/ton Reduction	14	4	15	22	39	62	58	108	109

Source: Forecast at 2.3% is Victor Wood's Montana Coal Market Study (July 1984). Assumes Base Montana price of 9.75 and 8600 BTU and Wyoming of 7.50 and 8300 BTU.

Comparison is to the present study with a base of $9.50 Montana (8700 BTU) and 7.70 Wyoming (8450 BTU).

Chapter IV. Acid Rain and Montana Coal Demand

A. Market Size

Another potential market for Montana coal is the set of older plants, mainly in the midwestern states, that currently burn high sulfur fuels. Because of the increased scientific evidence that links coal-fired generating plant emissions of SO_2 with acid precipitation impacts, a number of bills were proposed in the last congress to reduce SO_2 emissions by 8 to 12 mtpy. The bills are of two major types. The Sikorsky/Waxman Bill (HR3400) for example, would require scrubbers on the "top 50" emitters and leave a potential of 30 to 50 mtpy of high sulfur coal use that could be switched to low sulfur. The other type of bill, typified by S2001, the Durenburger Bill, would have no explicit technology forcing provisions. Utilities would be free to choose the lease cost mix of scrubbing and switching on their system. The latter, of course, could be constrained by state-level regulations that would protect the local high sulfur coal industry to varying degrees. At 10 mtpy SO_2 reduction, there is a total of 220 mtpy that could be scrubbed or switched.

At present there is a great deal of uncertainty over the target level of reduction and the means of achieving that reduction. It is probable that no acid rain bill will pass in the current congress.

A maximum potential acid rain market for the NGP is estimated in Table 22, based on tonnages delivered in 1983 to plants facing sulfur emission regulations more lenient than 3.0 lbs. SO_2/MMBTU. As is evident, the bulk of the "acid rain" plants are in states on the fringe of, or outside our historical market identified in Chapter 2, such as Ohio, Illinois, and Indiana. In the states where Montana coal specifically may have a clear competitive edge such as Montana and Minnesota, there are either no older plants or they are already burning low

Table 22

Maximum Potential Acid Rain Capacity in Coal Market Area

State	Mil. Tons	1983 MT WY Deliveries	Maximum Potential
Minnesota	4.6	4.4 MT	.170
Wisconsin	6.7	.5 MT	6.28
Missouri	16.3	--	16.3
Illinois*	16.0	--	16.0
Indiana*	26.7	--	26.7
Ohio*	37.7	--	37.7
Kansas	4.1	2.7	1.5
Michigan	10.8	.8	10.0
Iowa	5.3	3.2	2.2
Total	128.2	11.6	116.6
*Market Fringe	79.4		79.4
Residual	48.8		37.2

Total tonnage by state with plants facing sulfur regulations equal to or more lenient than 3.0 lbs. $SO_2/10^6$ BTU.

Source: Derived 1983 Cost and Quality, DOE.

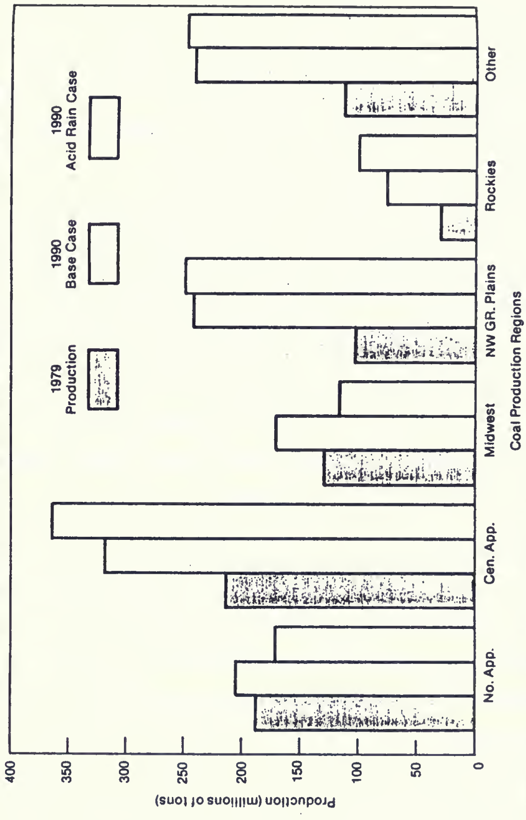
sulfur coal. For example in Minnesota, Wisconsin, and Michigan there is a total potential of only 16.5 mtpy. The traditional Wyoming market also has few high sulfur plants, with the exception of Missouri (16.3 mtpy), because the south-central states have historically used gas and oil.

While the potential "acid rain" market for the NGP may be anywhere from 37 to 117 mtpy, the actual share will depend critically on the type of legislation (scrub or switch) and on the unit-specific economics. Many of the older plants designed for bituminous coals may not be able to burn the low BTU, high ash western coals, or burn them only at a large expense. An analysis by ICF that takes into account the match of unit and coal source characteristics, and assumes that utilities will minimize costs, is summarized in Figure 12. By 1990, acid rain legislation would only add 10 mtpy to the NGP market. Based on historical market shares, this would imply perhaps 2.5 mtpy for Montana. It is important to note that ICF assumed the Durenburger type of bill that did not mandate scrubbing. In short, even under the most optimistic scenario (there is an acid rain bill and it allows utilities to scrub or switch), the Montana market for acid rain plants is anywhere from 0 to 3 mtpy.

The conclusion here is that acid rain plants are not likely to add significantly to the Montana market.

Figure 12

Regional Coal Production: Effects of a 10-Million-Ton Sulfur Dioxide Emission Reduction



SOURCE: Office of Technology Assessment, adapted from ICF, Inc.

B. Acid Rain Legislation

Although the new Congress has only been in session a few weeks, representatives, staff and observers all agree that it is very unlikely new acid rain legislation will pass this session. This assessment, together with the Administration's reluctance to propose or back one of the many SO_2 reduction plans introduced last session, essentially assures that the status quo will pertain for at least two more years.

In addition, the Administration's position is that further studies are necessary before an adequate bill can be drafted. At the same time, funding for such studies will be restricted, or non-existent, given the tight budget situation. In the next few years, then, it is unlikely that federal legislation will change the current supply relations dramatically. Utilities will be guided by current rules and laws in assessing the mix of coals, scrubbing and emissions that provide compliance and the lowest cost for a particular electrical generating boiler.

It is also constructive to look ahead, at least a short time, and assess the likely introduction of new acid rain legislation. The passage of national environmental legislation, any legislation, requires building a momentum for passage over two or more legislative sessions. That momentum will be broken in the current session to the point that some observers and staff suggest that leading House supporters of specific legislative initiatives may not even ask for committee hearings. In addition, few pieces of legislation can finally become law without Presidential signature, and active Presidential support will be needed to successfully negotiate the Congress. Acid rain is a bipartisan issue, but few Senators, perhaps, would want to challange Presidential leadership on this issue, knowing a veto lies at the end of the legislative road.

Given the current mood of the National Congress, the pull-back of legislative leaders who championed acid rain reduction in the last Congress, and the Presidential (E.P.A.) assessment of new study requirements, it appears unlikely that acid rain reduction will be mandated by the Congress in this decade. New contract potential for Montana and Wyoming based upon some form of SO_2 reduction does not seem likely before the 1990's at the earliest. Even then, given the uncertainty about the form, requirements and timing of any new legislation, the level of impact on Montana and Wyoming is uncertain. In any case, whatever may develop in the 1990's to enhance air pollution control and increase Northern Great Plains coal production is certain to benefit Wyoming more than Montana because of the geographic relation to the new markets.

Chapter V. Severance Tax Analysis

This chapter provides an analysis of the impact of changes in the Montana coal severance tax on the three market categories previously identified: existing contracts, new plants, and acid rain plants.

A. Magnitude of the Severance Tax

The Montana and Wyoming coal and severance tax and other state and local taxes are compared in Table 23. On an overall basis Montana's total taxes are 25% of selling price versus 17% for Wyoming. The severance taxes alone are 21% and 11%. On Western Energy coal in 1983, for example, the Montana coal severance tax was 2.30 $/ton or about 13¢/MMBTU. A change of 50% in the tax would amount to $1.15 and 6 1/2¢/MMBTU or about the difference in the Montana and Wyoming taxes. The table does not reflect the new royalty deduction which is being phased in and will reduce the Montana effective rate to about 18% in 5 years.

In relation to typical delivered prices, for example in the Minnesota market (recall Figure 2), of $25 to $30/ton even a 50% reduction in the tax is only 4 1/2% of delivered prices. In short, on *a priori* grounds one would not expect very significant changes in the Montana market due to even very large changes in the tax. Recalling the dominant effect of location discussed in Chapter 2, a 50% tax reduction would alter locational advantage by only about 67 miles for 8700 BTU Montana coal.

B. Impact on the Market

Theoretical Model

The theoretical impact of a tax reduction on production and tax revenue is outlined in Figure 13. The model assumes that the tax is completely forward shifted (perfectly elastic supply) so that tax cuts are reflected exactly in

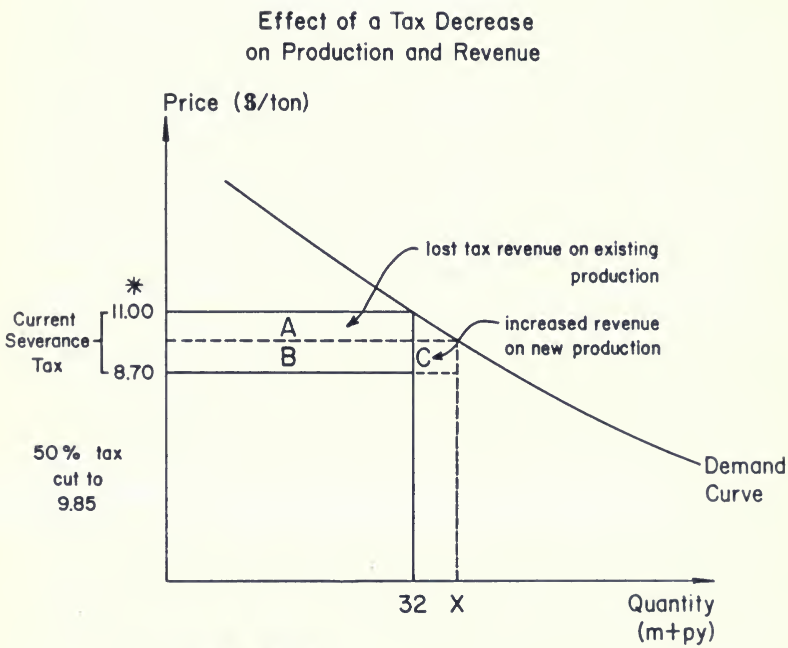
Table 23

Montana and Wyoming Taxes as a Percent of Selling Price

	Montana	Wyoming
Severance Tax	21.34	10.50
Property Tax	3.40	5.92
Sales Tax	N/A	0.24
State Income Tax	.46	N/A
State and Local Sub	25.20	16.66

Source: The Competitive Position of Colorado Coal: A Comparative Analysis of Coal Taxation in Six Western States and Texas Gennifer Sussman et al April 1984. (Colorado Energy Research Inst.)

Figure 13



A + B = current revenue.
A = lost revenue under tax reduction.
C = revenue on new production.
C − A = net change in tax revenue.

Issue: X = new production level (elasticity of demand).
* Average price of 8700 BTU producers, for example.

in price changes. (This may result in an overestimate of the price change depending on tax incidence.) A given tax cut can then be expected to reduce price and increase production. Schematically the area "A" is lost tax revenue "C" is tax gained on increased production. As illustrated, losses far outweigh gains. In fact the magnitude of "A" vs. "C" depends on the response of increased quantity demanded to a given price change. The unknown new production level is indicated by "X" and will in general depend on the "elasticity of demand." The latter is simply the percent change in quantity demanded for a percent change in price. In Figure 14 a much more elastic demand curve is illustrated with a much larger new "X" (here Q_1). Even here losses continue to dominate gains. In fact, an exact "break even" elasticity for a tax cut to result in no change in tax revenues can be calculated (Figure 15). The basic finding is that demand would have to be extremely responsive to price changes (an elasticity of around -5.0) in order for tax revenue to be stable. In fact, it is highly unlikely that the long run elasticity of demand for Montana coal is much over -1.0, as noted in Chapter III.

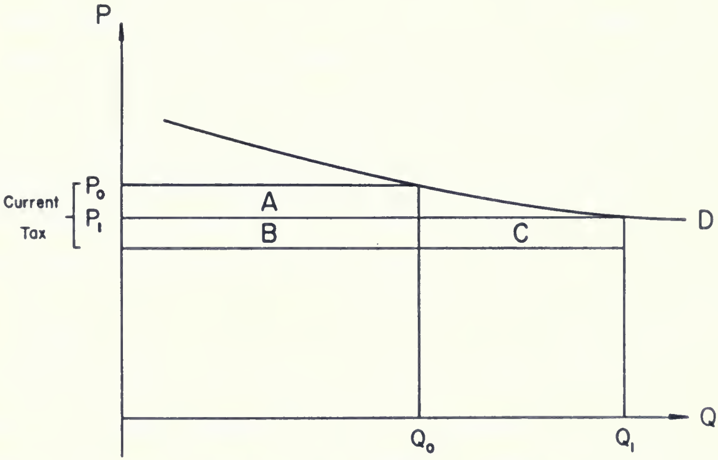
Timing Issues

To analyze the impact of a given tax change, it is necessary to identify the lag between coal sourcing decisions and on-line dates for new coal-fired units. Decisions on plants coming on line 5 to 10 years from now are based on current and projected economics. In short the impact of a tax change is delayed, or, conversely, to affect plant decisions in the future, one has to change taxes in the near term.

A summary estimate of the timing is provided in Figure 16. Based on the Boiler order date vs. on-line date information provided earlier, utilities must be making decisions relating to coal rank (i.e. lignites vs. subbituminous vs. bituminous) at least 8 to 10 years in advance. On the other

Figure 14

Tax Decrease with
Highly Elastic Demand



Here net loss to a tax reduction (C−A) is reduced by large production response to a small price change (highly elastic demand).

Analytical: need an elasticity of about −4.6 to "breakeven".

Figure 15

Tax Revenue/Elasticity of Demand Relationship

Independent Relationships:

1. <u>Total Tax</u>

$$T = t_e(P-K_2)Q \qquad \text{or}$$

$$= (t_s/1 + t_s)\ (P-K_2)Q$$

2. <u>Tax Formulas</u>

$$P = \frac{K_1}{(1-t_e)} + K_2$$

$$\left(t_e = \frac{t_s}{1 + t_s}\right)$$

<u>where</u>: K_1 = Contract Sales Price

K_2 = fixed deductions (black lung, etc.)

P = FOB

t_e = effective tax rate

t_s = severance tax rate

3. <u>Empirical Demand</u>

$$\frac{dQ}{dP} \cdot \frac{P}{Q} = E_d$$

<u>then</u>:

$$\frac{dT}{dt_e} = QP(1 + Z\ [1 - \left|E_d\right|]) - K_2Q(1 + \frac{K_2}{Q}\frac{dQ}{dt_e})$$

where:

$$Z = \frac{K_1 t_e}{(1 - t_e)(K_1 + K_2[1 - t_e])}$$

solve for $\left|E_d\right|$ when

$$\frac{dT}{dt_e} = 0 \qquad \text{and} \qquad K_1,\ K_2,\ t_e,\ Q \quad \text{(given exogenous)}$$

for t_e = .23; K_1 = 7.79; K_2 = .85; P = 11.00 "breakeven" E_d = -4.69

Discrete approximate for Δt_e = .01 "breakeven" E_d = -5.06

Figure 16

Severance Tax Issue:

Timing

Market Sector Impacted	Timing re-market
1. Existing	~1 year
2. New Plants	3-5 year--source 8-10 year--rank
3. Acid Rain	~1 year

hand, within coal ranks, specific coal source decisions may be 3-5 years lead. For example, the NSP Sherco #3 unit bids were taken in November 1984 for a late 1987 start, or three years lead. (In fact the decision is only a 2.5 year lead.) It is presumed that existing contract renewals would be essentially based on the market price near the time of contract renewal, or one year.

Near Term Impacts

Given the timing assumed in Figure 16, a decision to change the severance tax in this legislature (1985) would potentially impact contract renewals through 1986, new plant coal source decisions for plants coming on line from 1988 to 1990 and new plant coal rank decisions for plants coming on in 1993 and 1995. Based on the historical analysis in Chapter 2, it seems unlikely that a change in delivered price on the order of 7¢/MMBTU will significantly alter the subbituminous-bituminous-lignite market shares. Assuming then that the dominant effect of a tax change will be vis-a-vis Wyoming coals, the impacts, if any, will be on plants coming on line before 1988 to 1990. The qualification "if any" here is important. In the following a "naive model" is assumed, that Wyoming will not strategically respond to Montana tax cuts. Since the latter is a possibility, the results below are likely, if anything, to be overestimates of the gains to tax cuts.

Given the timing and magnitude of the tax cut, we know the relevant markets that could be affected. If the impact at most would be restricted to new plants on line to 1990, in the Montana market area the impact is on one plant--the Sherco #3 unit. Based on the discussion above, it appears that Montana already has a competitive edge at this plant. Expanding the time frame to include 1993 may only pick up one other plant in Wisconsin or about 1 1/2 mtpy. In short, based on the near term analysis of the potential new plant market, to 1993 a severance tax cut of 50% would possibly impact decisions on about 3 1/2 mtpy of

new plant capacity. This would add at most about 3.5 mtpy to the 41 mtpy forecast for 1988, or about plus 8% in coal production for a price change of about 10%. This implies inelastic demand (around -0.8) to 1993 and would clearly result in very large decreases in tax revenue.

C. Decision Criteria

At this point it is useful to raise the issue of an appropriate basis for estimating the impacts of severance tax changes. It appears that the state faces a problem of evaluating multiple goals. At a minimum a decision criteria should weigh both tax revenue changes and changes in coal production levels (or coal revenues, producer profit, employment, etc.). For example, a hypothetical decision criteria could be specified as follows:

$$\text{SOCIAL WELFARE} = W_1 \text{ (TAX REVENUE)} + W_2 \text{ (COAL PRODUCTION)}$$

where W_1 and W_2 are weighting terms. What this equation suggests is that in some sense "social welfare" or "the public good" effect of a change in the severance tax is a weighted average of tax revenue changes and coal production with the weights essentially reflecting distributive assumptions on how we as a state evaluate a $1 of tax revenue accruing to the state as a whole compared to a $1 of coal production profits (jobs, revenue, or etc.) accruing to coal producers and other impacted sectors.

It is beyond the scope of this analysis to identify an appropriate index for coal production or to propose the appropriate weights. However, it is possible to at least quantify the tax revenue ($) versus coal production (mtpy) tradeoff for use by decision makers. For the near term case above, it appears that the net effect of a 50% tax cut would be mainly in the new plant market to 1993. Existing contracts do not begin to expire until 1993, even assuming the tax would have an impact. Acid rain should probably be assigned a zero probability by 1993 for an expected value of zero.

D. Analysis of Tax Policy Alternatives

Several coal severance tax policy alternatives have been proposed. One specific proposal is a 50% cut in the severance tax on all production. Another is a 50% cut in the severance tax, but to be applied only to new production (presumably over the 1984 base of around 32.3 mtpy).

On our base case price of 9.50 $/ton, a 21% effective tax rate generate $2/ton in severance tax. Accordingly, for 8700 BTU coal, a 50% tax cut corresponds to our $1/ton price reduction cases. However, on the average Montana coal in 1983, a 50% tax cut would actually amount to about a $1.50 (since higher price Decker and Spring Creek coals are included).

Table 24 provides a summary of the effect of a $1/ton, $1.50/ton, and $2/ton severance tax reduction on a new production. As noted previously, there will be substantial growth in new production even in the absence of a tax cut. For example, our forecast at 2% growth in the year 2000 is for 31 mtpy of new production over the 1984 base case. A $1/ton tax reduction results then in a $31 million/year revenue loss on new production that would occur even without the tax cut. The $1 reduction stimulates additional new production of 5.7 mtpy which may bring in a tax revenue of around $11.4 million per year that would otherwise not be realized. (The latter assumes that new production was the same price and BTU [Decker, Spring Creek, other] mix as current. If in fact new production was mainly 8700 BTU coal, incremental taxes would approach only $1/ton for an increase of $5.7 million per year.) The net effect is then a $19.6 million loss in year 2000 at a 2% growth rate for coal production. Estimates for other years and growth percentages, and price reductions are provided in Table 24. The $1.50 case is interpolated.

Using 2% growth as a base case, results for a cut in taxes on new production for a 50% reduction are summarized in Table 25. The net annual

Table 24

Annual Tax Revenue Changes
for Severance Tax Reductions

Year	1990			1995			2000		
Electric Growth	1%	2%	3%	1%	2%	3%	1%	2%	3%
New Production (mpty)	6.0	9.0	11.0	10.0	14.0	32.0	16.0	31.0	53.0
Change for $1 Price Reduction (mpty)	.9	1.5	1.3	1.6	1.2	6.9	1.0	5.7	13.5
Change for $2 Price Reduction (mtpy)	3.1	3.2	2.4	3.3	2.4	12.9	5.6	10.2	27.2
Change for $1.50 Price Reduction (mtpy)	2.0	2.4	1.9	2.5	1.8	9.9	3.3	8.0	20.4
	Revenue Change (million $/year)								
A. $1 Tax Reduction									
Loss on New Base	6.0	9.0	11.0	10.0	14.0	32.0	16.0	31.0	53.0
Gain on Change	1.8	3.0	2.6	3.2	2.4	13.8	2.0	11.4	27.0
Net Loss	4.2	6.0	8.4	6.8	11.6	18.2	14.0	19.6	26.0
B. $2 Tax Reduction									
Loss on New Base	12.0	18.0	22.0	20.0	28.0	64.0	32.0	62.0	106.0
Gain on Change	3.1	3.2	2.4	3.3	2.4	12.9	5.6	10.2	27.2
Net Loss	8.9	14.8	20.4	16.7	25.6	51.1	26.4	51.8	78.8
C. 50% Tax Change (1.50)									
Loss on New Base	9.0	13.5	16.5	15.0	21.0	48.0	24.0	46.5	79.5
Gain on Change	3.0	3.6	2.9	3.8	2.7	14.9	5.0	12.0	30.6
Net Loss	6.0	9.9	13.6	11.2	18.3	33.1	19.0	34.5	48.9

Table 25

Summary Tax Policy Analysis

Tax Policy Alternative	1985 Tax (10^6 \$)	1985 Coal (mtpy)	1990 Tax (10^6 \$)	1990 Coal (mtpy)	1995 Tax (10^6 \$)	1995 Coal (mtpy)	2000 Tax (10^6 \$)	2000 Coal (mtpy)
	Change in Tax Revenues (million \$/year) and Coal Production (million \$/year)							
A. 50% Tax Cut on New Production:								
Loss on Base Case New Production:			13.5		21.0		46.5	
Tax on Increase in New Production:			3.6	2.4	2.7	1.8	12.0	8.0
Net Effect:			9.9	2.4	18.3	1.8	34.5	8.0
B. 50% Tax Cut on All Production:								
Loss on Existing Production:	48.5		48.5		48.5		48.5	
Net Effect New Production:			9.9	2.4	18.3	1.8	34.5	8.0
Total	48.5		58.4	2.4	66.8	1.8	83.0	8.0

revenue loss is estimated to be $9.9 million in 1990 and $18.3 and $34.5 million in 1995 and 2000. The corresponding production gains are 2.4, 1.8 and 8.0 mtpy.

The other basic type of proposal is to reduce taxes on all production. For a 50% tax or $1.50 average price reduction this results in an immediate 48.5 million/year tax revenue loss on existing production plus the same net effect on new production as the previous case. Accordingly, the annual revenue loss is $60 to $80 million/year after 1990 (Table 25). Results using Victor Wood's estimates are similar, with revenue losses that are about $5 million/year higher in 1995 and 2000 (Table 26) and lower by the same amount in 1990.

The conclusion here is that estimates derived from both Wood's and this study are in substantial agreement. The basic finding is that tax cuts results in large revenue losses on new production that would occur in any case, even without tax on price cuts. The gain in tax revenue (at a reducted rate) on production stimulated by tax cuts are small, corresponding to the small gains identified earlier. In general the losses for a tax cut just on new production dominate the revenue gains by a ratio of 4:1 (Table 25). The annual tax revenue loss associated with production gains average at a minimum around $4 million annually per 1 mtpy of production gain. If the tax reduction is extended to all coal production, the tax revenue "cost" is $24.3 million per 1 mtpy in 1990, $37.1 million in 1995 and $10.4 million in 2000.

In order to get an aggregate estimate of these annual losses, one needs to take account of the time value of money. When this is done, on a present value basis (assuming a 3% real discount rate and constant 1984 dollars), the net cost of a 50% tax cut on new production only is around $150 million for the 1990-2000 period. The net cost of a 50% tax cut on all production is around $730 million

Table 26

Comparative Tax Policy Analysis

Year	1990	1995	2000
Production Estimates (mtpy)			
A. Present Study (2% elect. growth)			
New Production	9.0	14.0	31.0
New for $1 Price Change	1.5	1.2	5.7
*New for $1.50 Price Change	2.4	1.8	18.0
New for $2 Price Change	3.2	2.4	10.2
B. Victor Wood (2.3% elect. growth)			
New Production	3.0	21.0	50.0
New for $1 Price Change	0.0	1.0	7.0
*New for $1.50 Price Change	0.5	6.0	22.5
New for $2 Price Change	1.0	11.0	38.0
Tax Revenue Loss (million $/year)			
A. Present Study			
$1 Reduction	6.0	11.6	19.6
50% Reduction	9.9	18.3	34.5
$2 Reduction	14.8	25.6	51.8
B. Victor Wood			
$1 Reduction	3.0	19.0	36.0
50% Reduction	3.8	22.5	41.2
$2 Reduction	5.0	31.0	62.0

*Interpolated

Table 27

Present Value Basis Comparison
of Severance Tax Policy Alternatives
and Montana Coal Production

Policy	Electric Growth Rate	Production Gain (million tons per year)			Tax Revenue Loss (million $/year)
		1990	1995	2000	
A. 50% Tax Reduction on New Production					
	1%	2	2	3	105
	2%	2	2	8	150
	3%	2	10	20	205
B. 50% Tax Reduction on All Production					
	1%	2	2	3	685
	2%	2	2	8	730
	3%	2	10	20	785

for the 1985-2000 period. The production gains in both cases are around 2 mtpy in 1990 and 1995 and 8 mtpy in 2000 (Table 27). These estimates are for the base case of 2% electrical growth. If growth is more like 3%, the costs are around $205 million and $785 million for the two policies, for production gains of 2, 10, and 20 mtpy in 1990, 1995, and 2000. If growth is 1%, the costs are around $105 million and $685 million for production gains of 2 mtpy in 1990 and 1995 and 3 mtpy in 2000.

REFERENCES

Campbell, Thomas C. and Ming-jeng Hwang (1978). "Spatial Analysis and the Identification of Coal Markets," The Journal of Energy and Development 4, 104-125.

Chern, W.S. (1980). The Oak Ridge National Laboratory State Level Electricity Demand Forecasting Model, ORNL/NUREG-63. Oak Ridge, Oak Ridge National Laboratory.

Duffield, John and Arnold Silverman, Bradley Harr, Michael Lee, Danny Parker, and Donald Snow (1982). Projections of Coal Demand from the Northern Great Plains Through the Year 2010. Washington: Office of Surface Mining, U.S. Department of the Interior.

Hyson, C.D. and W.P. Hyson (1950). "The Economic Law of Market Areas," Quart. J. Econ. 64, 245-263.

Watson, W.D. Jr. (1972). "Cost of Air Pollution Control in the Coal-fired Electric Power Industry," Quart. Rev. Econ. and Bus. 12, 298-317.

Appendix A: Computer Program for Spatial Market Boundaries of the Northern Great Plains Coal Market Region

```
C   PROGRAMMER: MICHAEL H. LEE/ECONOMICS DEPARTMENT/U. OF M.
C                 ALTERED BY JOHN TUBBS/1984
C
C      PROGRAM: THIS PROGRAM CREATES DATA COORDINATES FOR SEVEN
C               MARKET BOUNDARIES, RESULTING IN A COMPLETELY
C               BOUNDED NGP COAL MARKET REGION.
C
C               DATE: OCTOBER  1984
C
      DIMENSION A(18,8)
      DIMENSION AMAP(101,32)
      DIMENSION STORE(101,4)
C
      DATA AA,AHALF,ATRAN,ATBT,ADUA,ADUB,APROD/7*0.0/
      DATA BB,BPROD,BTRAN,CC,DTHETA,DXOLD,DYOLD,DXNEW1/8*0.0/
      DATA DXNEW2,DYNEW1,DYNEW2,DD,DSCMKW,DIFFAB,DISTA,DS1,DS2/9*0.0/
      DATA EE,FIXTRA,FIXTRB,S1,S2,SUM,THETA,TONA,TONB,TMKW,TOTA/11*0.0/
      DATA TOTB,VARB,XCORD,XNEW1,XNEW2,YNEW1,YNEW2,YPOS/8*0.0/
      DATA TOTRA,TOTRB,FLAG,RATIO1,RATIO2,RATIO3,RATIO4/7*0.0/
      DATA SQDIST,TWICE,ANUM,SQNEG,AMKT,DECIDE,DISTAB/7*0.0/
      DATA DISTA1,DISTB1,DISTB/3*0.0/
      DATA RATIO5,CKNUM,CKDEN/3*0.0/
C
      DATA I,J,K,INTGR1,INTGR2,JARAY,NCOUNT,IROW,JCOL/9*0/
      DATA IDISA1,IDISB1/2*0/
C
C INITIALIZE STORE(I,J)
C TEMPORARY STORAGE OF COORDINATES PASSED TO AMAP.
      DO 20 J=1,4
         DO 10 I=1,101
            STORE(I,J)=0.0
   10    CONTINUE
   20 CONTINUE
C INITIALIZE A(I,J)
C ECONOMIC PARAMETERS USED TO GENERATE MARKET BOUNDARIES ARE IN A(I,J).
      DO 40 I = 1,18
         DO 30 J = 1,8
            A(I,J) = 0.0
   30    CONTINUE
   40 CONTINUE
C INITIALIZE AMAP)I,J)
C AMAP(I,J) HAS THE TRANSFORMED X & Y COORDINATES FOR THE 7 BOUNDARIES.
      DO 60 I = 1,101
         DO 50 J = 1,32
            AMAP(I,J) = 0.0
   50    CONTINUE
   60 CONTINUE
C
      WRITE(5,70)
   70 FORMAT(//,1X,'TYPE IN A FIVE LETTER CODE IDENTIFYING THIS RUN:')
      ACCEPT 80,ALPHA
   80 FORMAT(A5)
      WRITE(5,90)ALPHA
   90 FORMAT(//,1X,'THIS RUN IS: ',1X,A5,////)
C UNIT FOR22.DAT HAS INPUT DATA READ INTO A(I,J)
      READ(22,100,END=110)((A(I,J), J=1,8),I=1,18)
  100 FORMAT(8F)
  110 CONTINUE
C
      WRITE(5,120)




  120 FORMAT(/,6X,'COLORADO',6X,'ILLINOIS',8X,'NEW MEXICO',7X,
     1'TEXAS',9X,'UTAH',10X,'WASHINGTON',6X,'WYOMING',6X,'MONTANA',/)
      WRITE(5,130,END=140)((A(I,J),J=1,8),I=1,18)
  130 FORMAT(' ',8F)
  140 CONTINUE
C
      DO 540 JARAY = 1,8 ! LOOP THROUGH ALGORITHM FOR EACH OF 8 BDYS
         GOTO(150,160,170,180,190,200,210,215)JARAY
C
 150     CONTINUE
         THETA = 248.38        ! COLORADO
         GOTO 220
 160     CONTINUE
         THETA = 333.46        ! ILLINOIS
         GOTO 220
 170     CONTINUE
         THETA = 247.85        ! NEW MEXICO
         GOTO 220
 180     CONTINUE
         THETA = 300.06        ! TEXAS
         GOTO 220
 190     CONTINUE
         THETA = 222.69        ! UTAH
         GOTO 220
 200     CONTINUE
         THETA = 157.77        ! WASHINGTON
         GOTO 220
 210     CONTINUE
         THETA = 217.97        ! WYOMING
         GOTO 220
 215     CONTINUE
         THETA = 116.01        !MONTANA
 220     CONTINUE
C
         S1 = COSD(THETA)
         S2 = SIND(THETA)
C
```

```
C  THE NUMBER OF TONS OF COAL FOR ANNUAL OPERATION OF A GIVEN
C  COAL-FIFED POWER PLANT IS COMPUTED.
           AA = A(1,JARAY)*A(2,JARAY)
           BB = A(4,JARAY)*2000.00
           CC = A(3,JARAY)*1000.0
           DD = A(6,JARAY)*2000.0
           EE = A(5,JARAY)*1000.0
           TONA = (AA/BB)*CC
           TONB = (AA/DD)*EE
C
C FIXED TRANSPORTATION COSTS FOF A GIVEN QUANTITY OF CCAL PRODUCTION
C ARE COMPUTED.
           FIXTRA = TONA*A(14,JARAY)
           FIXTRB = TONB*A(15,JARAY)
C
C  ADDITIONAL COSTS ARE COMPUTED.
           DSCMKW = A(1,JARAY)*1000.0*A(9,JARAY)
           TMKW = A(2,JARAY)*A(1,JARAY)*1000.0
           ADDA = ( A(7,JARAY)*DSCMKW) + (A(10,JARAY)*TMKW)
           ADDB = ( A(8,JARAY )*DSCMKW) + (A(11,JARAY)*TMKW)
C
C  PRODUCTION AND TRANSPORTATION COSTS ARE COMPUTED.
           APROD = A(12,JARAY)*TCNA




           BPROD = A(13,JARAY)*TONB
           ATRAN = A(16,JARAY)*TCNA
           BTRAN = A(17,JARAY)*TONB
           TOTA = APROD + ADDA + FIXTRA
           TOTB = BPROD + ADDB + FIXTRB
C
C  THE FOLLOWING DETERMINES WHETHER THE MARKET BOUNDARY
C  INTERSECTS THE X-AXIS ON THE NEAR ON FAR SIDE OF MARKET B.
           DISTAB = A(18,JARAY)
           AMKT = TOTA + (ATRAN*DISTAB)
           DECIDE = AMKT - TOTB
  230      CONTINUE
           IF(DECIDE.LT.0.0) GOTO 370
C
C  DISTA IS COMPUTED FOR THE CASE THE MARKET BOUNDARY INTERSECTS
C  THE X-AXIS BETWEEN MARKETS A AND B.
           DIFFAB = TOTB-TOTA
           VARB = BTRAN * DISTAB
           SUM = DIFFAB + VARB
           ATBT = ATRAN + BTRAN
           DISTA = SUM / ATBT
C
C      TOTAL TRANSPORTATION COSTS ARE COMPUTED.
           TOTRA = FIXTRA + A(16,JARAY)*DISTA
           TOTRB = FIXTRB + A(17,JARAY)*(DISTAB-DISTA)
C
C  COMPUTE DATA USED IN GENERATING BOUNDARIES.
           AHALF = DISTAB / 2
           DISTB = DISTAB - DISTA
           IF(DISTA.EQ.DISTB)  GOTO 460
           RATIO1 = ATRAN/BTRAN
           RATIO2 = (TOTA-TOTB)/BTRAN
           RATIO3 = 1/RATIO1
           RATIO4 = (TOTB-TOTA)/ATRAN
           SQDIST = DISTAB**2
           TWICE  = 2 * DISTAB
           IF(DISTA.LT.AHALF)  GOTO 300
  240      CONTINUE
C
C  BELOW LOOP IS FOR THE CASE WHEN A BOUNDARY OPENS TO MARKET B.
           INTGR1 = INT(DISTA + 5)
           INTGR2 = INTGR1 + 1000
           I = 0
           FLAG = 0.0
           DO 290 IDISAI = INTGR1,INTGR2,10
              I = I + 1
              IF(I.GT.101) GOTO 290
              J = 1
              IF(FLAG.GT.1.0) GOTO 250
              XCORD = DISTA
              YPOS = 0.0
              GOTO 270
  250         CONTINUE
              DISTBI = (IDISAI * RATIO1) + RATIO2
  260         CONTINUE
              ANUM = IDISAI**2 - (DISTBI**2) + SQDIST
              XCORD = ANUM/TWICE
              SQNEG = IDISAI**2 - (XCORD**2)
              IF(SQNEG.LT.0.0) GOTO 280 !FOR ELLIPSES AND CIRCLES
              YPOS = SQRT(SQNEG)
```

```
 270        CONTINUE
            CALL EUCLID(XCORD,YPOS,XNEW1,YNEW1,XNEW2,YNEW2,S1,S2)
 280        CONTINUE
            STORE(I,J)=XNEW1
            J=J+1
            STORE(I,J)=YNEW1
            J=J+1
            STORE(I,J)=XNEW2
            J=J+1
            STORE(I,J)=YNEW2
            FLAG = 100.0
 290     CONTINUE
         GOTO 490
C
C  BELOW LOOP IS FOR THE CASE WHEN A BOUNDARY OPENS TO MARKET A.
 300     CONTINUE
         INTGR1 = INT(DISTB + 5)
         INTGR2 = INTGR1 + 1000
         I = 0
         FLAG = 0.0
         DO 360 IDISBI = INTGR1,INTGR2,10
            I = I + 1
            IF(I.GT.101) GOTO 360
            J = 1
            IF(FLAG.GT.1.0) GOTO 310
            XCORD = DISTA
            YPOS = 0.0
            GOTO 340
 310        CONTINUE
            DISTAI = ( IDISBI*RATIO3) + RATIO4
 320        CONTINUE
            ANUM = DISTAI**2 - (IDISBI**2) + SQDIST
            XCORD = ANUM / TWICE
            SQNEG = DISTAI**2-(XCORD**2)
            IF(SQNEG.LT.0.0) GOTO 350
            YPOS = SQRT(SQNEG)
 330        CONTINUE
 340        CONTINUE
            CALL EUCLID(XCORD,YPOS,XNEW1,YNEW1,XNEW2,YNEW2,S1,S2)
 350        CONTINUE
            STORE(I,J)=XNEW1
            J=J+1
            STORE(I,J)=YNEW1
            J=J+1
            STORE(I,J)=XNEW2
            J=J+1
            STORE(I,J) = YNEW2
            FLAG = 100.0
 360     CONTINUE
         GOTO 490
C
C  FIND THE INTERSECTION POINT OF THE MARKET BOUNDARY WITH
C  THE X-AXIS.
 370     CONTINUE
         CKNUM = BTRAN*A(6,JARAY) ! HEAT CONTENT B
         CKDEN = ATRAN*A(4,JARAY) ! HEAT CONTENT A
         RATIO5 = CKNUM/CKDEN
         IF(RATIO5.GT.1.0) GOTO 440
         DIFFAB = TOTB-TOTA
         VARB = BTRAN * DISTAB




         SUM = DIFFAB - VARB
         ATBT = ATRAN-BTRAN
         DISTA = SUM / ATBT
C
         IF(DISTA.GT.0.0) GOTO 390
         WRITE(5,380) JARAY
 380     FORMAT(' ',////,'DISTA IS NEGATIVE FOR JARAY<',1X,I)
         GOTO 520
 390     CONTINUE
C
C  COMPUTE TOTAL TRANSPORTATION COSTS
         TOTRA = FIXTRA + A(16,JARAY)*DISTA
         TOTRB = FIXTRB + A(17,JARAY)*(DISTA-DISTAB)
C  COMPUTE DATA FOR GENERATING THE MARKET BOUNDARY
         RATIO1 = ATRAN/BTRAN
         RATIO2 = (TOTA-TOTB)/BTRAN
         SQDIST = DISTAB**2
         TWICE  = 2*DISTAB
C
```

```
C  [illegible] ON THE OTHER SIDE
C  OF MARKET B.
          INTGR1 = INT(DISTA + 5)
          INTGR2 = INTGR1 + 1000
          I = 0
          FLAG = 0.0
          DO 430 IDISAI = INTGR1,INTGR2,10
              I = I + 1
              IF(I.GT.101) GOTO 430
              J = 1
              IF(FLAG.GT.1.0) GOTO 400
              XCORD = DISTA
              YPOS = 0.0
              GOTO 410
 400          CONTINUE
              DISTBI = ( IDISAI*RATIO1 ) + RATIO2
              ANUM = IDISAI**2 - (DISTBI**2) + SQDIST
              XCORD = ANUM / TWICE
              SQNEG = IDISAI**2 - (XCORD**2)
              IF(SQNEG.LT.0.0) GOTO 420
              YPOS = SQRT(SQNEG)
 410          CONTINUE
              CALL EUCLID(XCORD,YPOS,XNEW1,YNEW1,XNEW2,YNEW2,S1,S2)
 420          CONTINUE
              STORE(I,J) = XNEW1
              J=J+1
              STORE(I,J) = YNEW1
              J=J+1
              STORE(I,J) = XNEW2
              J=J+1
              STORE(I,J) = YNEW2
              FLAG = 100.0
 430      CONTINUE
          GOTC 480
C
 440      CONTINUE
          WRITE(5,450)JARAY
          WRITE(5,450)JARAY
 450      FORMAT(' ',///,1X,'THE MARKET BOUNDARY FOR JARAY EQUAL TO',1X
     1,I,1X,'DOES NOT EXIST')
          GOTC 520




C
 460      CONTINUE
          WRITE(5,470) JARAY
 470      FORMAT(' ',///,'THE MARKET BDY FOR JARAY EQUAL TO:',1X,I,1X,'I
     1S A STRAIGHT LINE.')
          GOTO 520      ! ENTER LOOP AND PROCESS NEXT STATE
C
 480      CONTINUE
          WRITE(5,490) JARAY,TONA,TONB,ADDA,ADDB,APROD,BPROD,DIFFAB
     1,TOTRA,TOTRB,DISTA
 490      FORMAT(///,' ','STATE NUMBER',3X,I,//,' ','THE QUANTITY OF COA
     1L REQUIRED FOR THE ANNUAL OPERATION',/,' ','OF A MODEL COAL
     2 FIRED GENERATING PLANT FOR COAL FROM MARKETS A & B EQUALS',
     3 /,' ',2(1X,F11.2),/,' ','THE ADDITIONAL COSTS FOR COAL FROM
     4 MARKETS A & B EQUALS:',/,' ',2(1X,F11.2),/,' ','PRODUCTION
     5 COSTS FOR COAL FROM A & B EQUALS:',/,' ',2(1X,F11.2),/,' ',
     6 'THE DIFFERENCE IN TOTAL COST EQUALS:',1X,F11.2,/,' ','TOTAL
     7 TRANSPORTATION COSTS FOR A & B EQUALS',2(1X,F11.2),/,' ',
     8 'DISTA EQUALS:',1X,F8.2,///)
C
C  FOR EACH STATE, THE X & Y VALUES OF THE BOUNDARY ARE READ FROM
C  STORE(I,J) INTO ARRAY 'AMAP'.
          DO 510 IROW=1,101
              DO 500 J=1,4
                  JCOL=K + J
                  AMAP(IROW,JCOL)=STORE(IROW,J)
 500          CONTINUE
 510      CONTINUE
 520      CONTINUE
          K=K+4
 530      CONTINUE
 540  CONTINUE
      DO 560 I=1,101
          WRITE(21,550,END=560)(AMAP(I,J),J=1,32)
 550      FORMAT(' ',(32(' ',F9.2)))
 560  CONTINUE
 570  STOP
      END
C*****************************************************************
C
C
C  SUBROUTINE EUCLID CREATES NEW COORDINATES FOR MARKET BOUNDARIES
C  BY ROTATING THE STANDARD BASIS VECTORS BY 'THETA' DEGREES.
      SUBROUTINE EUCLID(DXOLD,DYOLD,DXNEW1,DYNEW1,
     1DXNEW2,DYNEW2,DS1,DS2)
 999  DXNEW1 = ( DS1*(DXOLD)-DS2*(DYOLD) )
      DYNEW1 = ( DS2*(DXOLD)+DS1*(DYOLD) )
      DXNEW2 = ( DS1*(DXOLD)-DS2*(-DYOLD))
      DYNEW2 = ( DS2*(DXOLD)+DS1*(-DYOLD) )
      RETURN
      END
```

Appendix B: Montana and Wyoming Coal Contracts (uncorrected)

WYOMING COAL CONTRACTS

COAL NETWORK ASSOCIATION

Utility by Mine	Plant Name	$/ton	$/milbtu	State	CONTRACTS Began/Ends	DOE,ORIS #		BTU	SULFUR	ASH	ESTIMATED QUANT. (mton)
Amex Coal Co. Bell Ayr											
Dairyland Power Coop	Alma	31.85	1.61	WS	83/?	50733	4140	8100	0.50	6.0	200
Iowa Power & Light	Council Bluffs	20.69	1.24	IO	78/99	51407	1082	8025	0.50	7.0	1600
" " "	Des Moines	24.84	1.17	IO	75/94	51407	1083	8100	0.50	6.0	120
Portland Gen. Elec Co.	Boardman	15.66	0.89	OR	74/99	52370	6106	8025	0.48	7.0	1200
Amex Coal Co. Bell Ayr , Eagle Butte											
C&SW:Southwestern Elec	Flint Creek	23.69	1.42	LA	72/01	52744	6138	6125	0.40	6.5	1500
" " "	Welsh	29.16	1.74	LA	76/04	52744	6139	8125	0.48	6.5	4000
Interstate Pwr. & Lgt.	Lansing	33.34	1.94	IO	73/96	51403	1047	8065	0.50	7.0	700
Kansas City Pwr.& Lgt.	Iatan	22.69	1.28	MS	84/13	51477	6065	8125	0.48	6.5	2100
" " " "	LaCygne	21.35	1.23	KN	76/13	51477	1241	8125	0.48	6.5	1800
" " " "	Jeffrey	20.40	1.22	KN	77/13	51479	6066	8025	0.48	6.5	6500
" " " "	Tecumsen	45.23	2.16	KN	85/?	51479	1252	8025	0.50	6.0	175
Pub. Serv. Co.of Colo.	Comanche	20.25	1.19	CO	76/08	52408	470	8250	0.60	5.2	2100
" " " "	Pawnee	17.98	1.07	CO	76/08	52408	6248	8025	0.48	7.0	2500
" " " "	5 Southeast	0.00	0.00	CO	89/?	52408	8220	8100	0.50	6.0	1000
Wisconsen Power & Lgt.	Columbia	29.19	1.70	WS	78/83?	53332	8023	8120	0.48	7.0	1500
Amex Coal Co. Eagle Butte											
Kansas Power & Light	Lawrence	45.09	2.16	KN	85/?	51479	1250	8025	0.50	6.5	1300
" " "	Tolk	47.25	2.69	TX	79/16	52748	6194	6500	0.30	4.9	2000
Arco-Thunder Basin Black Thunder											
Lower Colo. River Autn	Sam K. Seymore Jr.	46.05	2.53								
Nebraska Public Pwr.D.	Gentleman	16.95	0.96	NB?	83/?	51988	6077	8800	0.40	6.0	2000
Oklahoma Public Pwr.D.	Muskogee	26.85	1.51	OK	77/93	52164	2952	8700	0.50	5.0	4000
" " "	Sooner	27.92	1.58	OK	73/93	52164	6095	8700	0.30	5.0	3600
Platte River Pwr. Auth	Rawhide	15.66	0.89	CO	83/85	52346	6761	8500	0.25	6.0	920
Southwestern Pub. Serv	Harrington	31.25	1.74	TX	77/16	52748	6193	9000	0.47	3.9	4800

" " "	Tolk	47.25	2.69	TX	81/17	52748	6194	7900	0.47	5.6	2000
Union Electric Co.	Sioux	32.35	1.48	MS	80/85	52997	2107	8500	0.34	5.0	500
" " "	Rush Island	29.45	1.38	MS	83/7	52997	6155	8800	0.39	5.0	100
Wisconsen Pwr. & Lgt.	Dawey,Nelson	37.42	1.72	WS	85/04	53332	4054	8700	0.34	5.0	500
" " "	Pulliam	46.46	1.94	WS	84/84	53333	4072	8700	0.34	5.0	500
Arco-Thunder Basin Black Thunder , Coal Creek											
Kansas City Pwr.& Lgt.	Iatan	22.69	1.28	MS	60/83?	51477	6065	8816	0.37	5.0	2100
Wisconsen Pwr. & Lgt.	Columbia	29.19	1.70	WS	84/84	53332	8023	8000	0.60	6.8	1000
" " "	Edgerwater	?	?	WS	84/02	53332	4050	8000	0.34	6.0	500
" " "	Weston	38.59	2.13	WS	81/16	53333	4078	8500	0.34	5.0	1000
Arco-Thunder Basin Coal Creek											
Wisconsen Pwr. Lgt.	Blackhawk	40.24	1.79	WS	82/02	53332	4048	8000	0.60	8.8	10
Exon Coal USA Inc. Caballo											
Basin Elec. Coop.	Laramie River	14.93	0.89	ND	82/07	50161	6204	8400	0.48	6.0	2900
Exon Coal USA Inc. Rawhide											
AEP : Ohio Pwr. Co.	Gavin, Gen. Jim,	50.80	7.43	OH	83/7	54028	8102	8000	0.48	6.7	105
Grand River Dam	GRDA #1	28.84	1.76	OK	82/00	51154	165	6200	0.35	6.0	1800
Houston Lgt.& Pwr.Co.	Parish,W A	46.84	2.75	TX	83/87	51352	3470	8200	0.50	6.0	4550
Iowa Pub Serv. Co.	Neal, George	29.07	1.59	IO	77/98	51408	1091	8055	0.40	8.0	2200
Kansas City Bd of Pub.	Nearman Creek	28.09	1.71	KN	83/7	51476	6064	8000	0.40	6.0	1500
?	Kemp	?	?	?	86/16	53256	127	8227	0.50	6.0	2400
Omaha Public Pwr. Dis.	North Omaha	35.60	1.74	NB	83/7	52172	2291	8000	0.48	6.0	70
" " " "	Nebraska City	20.92	1.27	NB	82/97	52172	6096	8000	0.48	6.0	1700
Wisconsen Elec. Pwr. C	Pleasant Prarie	26.16	1.60	WS	80/00	53330	6170	8055	0.48	6.0	2000
Glen Rock Coal Co. Johnson, J											
Pacific Pwr. & Lgt.	Johnston, Dave (mm)	12.48	0.82	?	80/90	52225	4158	7600	0.47	10.	2500
Kerr-McGee Coal Co. Jacobs Ranch											
Arkansas Pwr. & Lgt.	Independance	30.29	1.73	AK	82/83?	50105	6641	8800	0.40	6.5	1900
" " "	White Bluff	32.46	1.63	AK	77/99	50105	6009	6524	0.48	7.5	5000
Cen. Lousiana Pwr. Coo	Doiet Hills	0.00	0.00	LA	86/?	50490	51	6500	0.50	5.8	1000

Gulf States Pwr.	Nelson	38.44	2.17	TX	82/84	51209	1393	8525	0.48	5.7	1800
" " " "	Rodemacher	38.79	2.18	LA	78/01	50490	6190	8524	0.48	5.7	600
Kerr-McGee Coal Co. Jacobs Ranch, Clovis											
Cajun Elec. Pwr. Coop.	Big Cajun 2	39.39	2.41	LA	83/86	50399	6055	8100	0.50	6.5	2000
CEN&SW:Pub. Serv.of OK	Northeastern	32.22	1.90	OK	79/09	52413	2963	8500	0.50	6.5	3000
Houston Lgt. & Pwr. Co	Parish, W A	46.84	2.75	TX	77/03	51352	3470	8000	0.50	6.5	3000
Kiewit-Bighorn Bighorn											
Common Wealth Edison	Crawford	43.62	2.20	IL	76/88	50643	867	9000	0.80	10.	160
" " "	Fisk Street	61.85	3.25	IL	76/88	50643	886	9000	0.80	10.	50
" " "	Joliet	63.44	3.32	IL	76/88	50643	874	9000	0.80	10.	1200
" " "	Powerton	?	?	IL	76/88	50643	879	9000	0.80	10.	1800
" " "	Waukegan	59.86	3.14	IL	83/88	50643	883	9000	0.80	10.	100
" " "	Will County	60.58	3.19	IL	76/88	50643	884	9000	0.80	10.	270
Com. Wealth Edison/IN	State Line	50.21	2.43	IN	76/88	54003	981	9000	0.80	10.	25
Mobil Coal Producing Caballo Rojo											
Basin Elec. Coop	Laramie River	14.93	0.89	ND	82/02	50181	6204	8100	0.40	6.0	2500
Grand River Dam	GRDA #2	28.84	1.76	OK	85/10	51154	165	8100	0.50	6.0	2000
Sunflower Elec. Coop	Holcomb	25.57	1.56	KN	83/?	52855	108	8050	0.50	6.0	1250
Nerco-Antelope North Antelope											
Arkansas Pwr & Lgt.	Independence	30.29	1.73	AK	84/06	50105	6641	8675	0.28	5.5	5000
Nerco-Antelope Spring Creek (Antelope)											
Houston Lgt. & Pwr Co.	Parish, W A	46.84	2.75	TX	77/?	51352	3470	8500	0.25	6.0	2200
Louisiana Pwr. & Lgt.	Wilton	0.00	0.00	LA	90/10	51694	9999	8500	0.25	6.0	2500
Platte River Pwr. Auth	Rawhide	15.66	0.89	CO	86/03	52346	6761	8500	0.25	6.0	920
Snell Triton Coal Co. Buckskin											
Basin Elec. Coop.	Laramie River	14.93	0.89	ND	84/95	50180	6204	8000	0.50	7.0	250
Cajun Elec. Pwr. Coop	Big Cajun 2	39.39	2.41	LA	79/88	50399	6055	8100	0.50	6.2	2400
Western Farmers Elec.	Hugo	33.82	2.05	OK	83/?	53262	6772	8000	0.50	7.0	1300
Sun DCO Coal Co Cordero											

Basin Elec. Coop.	Laramie River	14.93	0.69	ND	82/02	50160	6204	8400	0.40	6.0	3000
Iowa-Illinois Gas&Ele	Louisa	28.53	1.69	IO	82/02	51406	6664	8100	0.30	6.6	1800
Iowa Pwr. & Lgt.	Council Bluffs	20.69	1.24	IO	83/?	51407	1082	8100	0.30	6.6	200
Iowa Southern Util.	Burlington	36.37	1.62	IO	77/01	51409	1104	8100	0.37	6.6	20
" " "	Ottumwa	23.96	1.42	IO	80/01	51409	6254	8100	0.37	6.6	1500
San Antonio Pub. Ser.	Deely, J T	35.53	2.11	TX	82/97	52567	6181	8300	0.40	6.2	2000
Wyodac Res. Dev.	Wyodac										
Black Hills Pwr.& Lgt	French, Ben	0.00	0.00	SD	77/88	50256	3325	7500	0.70	10.	400
" " " "	Kirk	"	"	SD	77/88	50256	3328	7500	0.70	10.	120
" " " "	Osage	"	"	SD	77/88	50256	4151	7500	0.70	10.	220
" " " "	Simpson, Neil	"	"	SD	77/88	50256	4150	7500	0.70	10.	130
Grand Island Util.	Platte	28.20	1.74	NB	78/01	51150	59	7720	0.50	7.5	350
Hastings Util. Dept.	Hasting	28.50	1.76	NB	83/?	51259	60	8100	0.40	6.0	120
Pacific Pwr. & Lgt.	Wyodac (mm)	7.29	0.45	WY	?/24	52225	6101	7500	0.70	10.	2500

1984 data from Coal Network Assoc., Inc. Fort Collins CO

MONTANA COAL CONTRACTS
COAL NETWORK ASSOCIATION

Utility by Mine	Plant Name	$/ton	$/milbtu	State	CONTRACT Began/Ends	DOE/ORIS #	BTU	SULFUR	ASH	ESTIMATED QUANT. (mton)
Westmoreland Res. Absaloka:										
Dairyland Power Coop.	Alma +	31.85	1.61	WS	83/?	50733 4140	8300	1.05	10.	120
" " "	Genoa	32.76	1.07	WS	83/?	50733 4143	8300	1.00	11.	350
Interstate Power Co.	Dubuque	35.17	1.67	IO	72/93	51403 1046	8000	1.00	14.	40
" " "	Lansing	33.34	1.97	IO	72/93	51403 1047	8000	1.00	14.	50
" " "	Fox Lake	39.84	2.29	MN	72/93	51403 1888	8000	1.00	14.	100
" " "	Kapp	?	?	IO	72/93	51403 1048	8000	1.00	14.	100
Marquette, City of	Shiras	40.38	?	MI	?/84	51776 1843	8450	0.75	10.	25
Northern States Pwr.	Black Dog	30.83	1.68	MN	72/93	52107 1904	8450	0.75	12.	100
" " "	River Side	27.44	1.44	MN	72/93	52107 1927	8450	0.75	11.	150
" " "	Sherburne Co	23.28	1.32	MN	83/?	52107 6090	8450	0.75	11.	1500
" " "	King	?	?	MN	72/93	52107 1915	8450	0.75	12.	700
" " "	High Bridge	?	?	MN	72/93	52107 1912	8450	0.75	11.	50
" " "	Minn. Valley	--	--	MN	lost cont prior to 1984					
Wisconsen Pwr. & Lgt.	Dewey,Nelson +	29.76	1.40	WS	74/93	53332 4054	8450	0.73	10.	150
Westmoreland Res Absaloka, Sarpy Ck:										
Central Illinois Lgt Co	E.D. Edwards	50.64	2.05	IL	73/93	50485 856	8100	1.00	9.0	250
Decker Coal Co Decker East:										
Common Wealth Edison Co.	Crawford +	43.62	2.30	IL	78/97	50643 867	9000	0.65	9.2	200
" " " "	Joliet +	63.44	3.32	IL	78/97	50643 874	9000	0.65	9.0	100
" " " "	Powertown +	49.21	2.63	IL	78/97	50643 879	9000	0.65	9.0	1600
" " " "	Waukegan +	59.86	3.14	IL	78/97	50643 883	9000	0.65	9.0	100
" " " "	Will County +	60.58	3.19	IL	78/97	50643 884	9000	0.65	9.0	300
Common Wealth Ed,Indiana	State Line +	50.21	2.64	IN	78/97	54003 981	9000	0.65	9.0	800
Illinois Pwr. Co.	Havana	--	--	IL	lost cont prior to 1984					

Lower Colo. River Autn.	Fayette	--	--	TX	lost cont prior to 1984						
Marquette, City of BD	Shiras	40.38	?	MI	?/84	51778	1843	9000	0.65	9.0	120
Decker Coal Co Decker West :----------											
Commonwealth Edison	Fisk Street +	61.85	3.25	IL	78/98	50643	886	9000	0.65	9.0	42
Detroit Edison Co.	Monroe	41.09	1.68	MI	73/99	50782	1733	9400	0.50	5.0	800
" " "	St. Clair	37.50	1.89	MI	72/99	50782	1743	9800	0.40	4.0	3800
" " "	Belle River (new plant)	0.00	0.00	MI	85/02	50782	6034	9600	0.50	5.0	4000
Lower Colorado River Aut	Sam K. Saymor????	46.05	2.53	TX	78/04	51702	6179	9200	0.50	4.5	2100
Upper Pen. Generating	Presque	--	--	MI	lost cont prior to 1984						
Western Energy Rosebud #6:----------											
Hibbing Public Util.	Hibbing	0.00	0.00	MN	?/83	51294	1979	8600	0.60	8.0	100
Lake Superior Dist Pwr.	Bay Front	0.00	0.00	WS	76/95	51570	3982	8600	0.90	8.5	50
Marquette City of BD	Shiras	40.38	?	MI	?/84	51778	1843	8300	0.90	9.0	25
Montana Power Co <MM>	Corette, J.E.	11.32	0.65	MT	69/89	51915	2187	8600	0.86	9.0	500
" " " "	Colstrip	12.18	0.72	MT	75/09	51915	6076	8300	0.90	9.0	3000
Northern States Power	Black Dog	30.83	1.68	MN	72/95	52107	1904	8300	0.90	9.0	60
" " "	High Bridge	32.28	1.69	MN	72/95	52107	1912	8300	0.90	9.0	50
" " "	Riverside	27.44	1.44	MN	72/95	52107	1927	8300	0.90	9.0	250
" " "	Sherburne	23.28	1.32	MN	?/95	52107	6090	8300	0.90	9.0	2500
" " "	King	?	?	MN	72/95	52107	1915	8300	0.90	9.0	500
United Pwr. Assn.	Elk River	--	--	MN	lost cont prior to 1984						
Virginia Pub. Util. Comm	Virginia	0.00	0.00	MN	83/?	53145	2018	8600	0.90	9.1	100
Willmar Municipal Util C	Willmar	0.00	0.00	MN	82/?	53305	2022	8500	0.75	8.5	60
Wisconsen Pwr. & Lgt.	Columbia +	29.76	1.40	WS	84/94	53332	8023	8700	0.73	[illegible]	1600
" " "	Dewey, Nelson	--	--	WS	lost cont prior to 1984						
Wisconsen Pub. Serv.	Pulliam	--	--	WS	lost cont prior to 1984						

Peabody Coal Co	Big Sky:										
Minnesota Pwr. & Lgt.	Aurora	0.00	0.00	MN	68/93	51880	1891	8700	1.30	10.	150
" " "	Boswell,Clay	20.90	1.21	MN	68/93	51880	1893	8600	1.30	10.	4200
Northern States Pwr.	Sherburne	23.28	1.32	MN	84/84	52107	6090	8700	0.70	10.	300
Knife River Coal Co.	Savage:										
Montana-Dakota Util.	Lewis & Clark	15.69	1.17	ND	73/93	51913	6089	6500	0.50	7.5	175

1984 data from Coal Network Assoc. , Fort Collins CO
1979 data from Duffield and Silverman (1982)

Appendix C. Input File: Spatial Market Model

This appendix provides a sample of the data input file for running the spatial market model. The basic data format is summarized in Figure C-1, and a sample input file (for the base case at MT FOB = $9.50 and WY FOB = $6.00) is provided in Table C-1. Each row in Table C-1 is identified in Figure C-1. The columns in Table C-1 each correspond to boundaries between Montana coal and one other coal supply center. The column sequence from left to right is: Colorado, Illinois, New Mexico, Texas, Utah, Washington, South Wyoming, and Wyoming supply centers.

The spatial market maps discussed in the text of this report were generated by varying FOB prices for Montana (line 12), FOB prices for Wyoming (column 8, line 13), and fixed transportation charges (to adjust for differences between air and actual rail mile distances by region).

Figure C-1

Variable Description for Market Boundary Parameters*

Line #	Coal Supply Center	Variable Description
1	A & B	Power plant size (net MW)
2	A & B	Hours operated at full load (hours)
3	A	Power plant heat rate (BTU/KWhr)
4	A	Coal heat content (BTU/lb)
5	B	Power plant heat rate (BTU/KWhr)
6	B	Coal heat content (BTU/lb)
7	A	Power plant capital cost ($/KW)
8	B	Power plant capital cost ($/KW)
9	A & B	Fixed charge rate (decimal)
10	A	Operating and maintenance costs ($/KWhr)
11	B	Operating and maintenance cots ($/KWhr)
12	A	FOB mine price ($/ton)
13	B	FOB mine price ($/ton)
14	A	Fixed transportation cost ($/ton)
15	B	Fixed transportation cost ($/ton)
16	A	Variable transportation costs ($/ton-air mile)
17	B	Variable transportation costs ($/ton-air mile)
18	A & B	Straight line distance between A & B (miles)

*Duffield, Silverman (1982) p. 8-55

Table C-1

BASE 84 MT FOB. = 9.50 , WY FOB. = 6.00

1	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0
2	5694.0	5694.0	5694.0	5694.0	5694.0	5694.0	5694.0	5694.0
3	10486.0	10058.0	10564.0	10251.0	10486.0	10486.0	10486.0	10486.0
4	8700.0	8700.0	8700.0	8700.0	8700.0	8700.0	8700.0	8700.0
5	10341.0	10204.0	10564.0	11045.0	10197.0	10486.0	10341.0	10486.0
6	10700.0	10500.0	10000.0	6300.0	11500.0	8100.0	10500.0	8450.0
7	1329.7	1167.3	1257.5	1049.3	1329.7	1329.7	1329.7	1329.7
8	1307.1	1206.8	1257.5	1357.0	1227.6	1333.5	1307.1	1329.7
9	0.07410	0.07410	0.07410	0.07410	0.07410	0.07410	0.07410	0.07410
10	.00671	.00633	.00665	.00630	.00671	.00671	.00671	.00671
11	.00665	.00822	.00665	.00699	.00660	.00775	.00665	.00671
12	9.50	9.50	9.50	9.50	9.50	9.50	9.50	9.50
13	21.25	25.52	25.00	11.92	26.30	27.22	16.50	6.00
14	2.02	2.02	2.02	2.02	2.02	2.18	2.02	2.02
15	2.18	5.30	2.02	2.02	2.18	2.02	2.02	2.02
16	.0246	.0256	.0265	.0265	.0246	.0265	.0246	.0246
17	.0265	.0256	.0265	.0265	.0265	.0246	.0246	.0246
18	395.7	1061.5	663.6	1106.6	521.6	779.1	321.6	252.8

Figure C-2

Montana Market Area for $1.00/Ton Price Reductions Against $7.70/Ton Wyoming Coal. Base is $9.50 Montana.

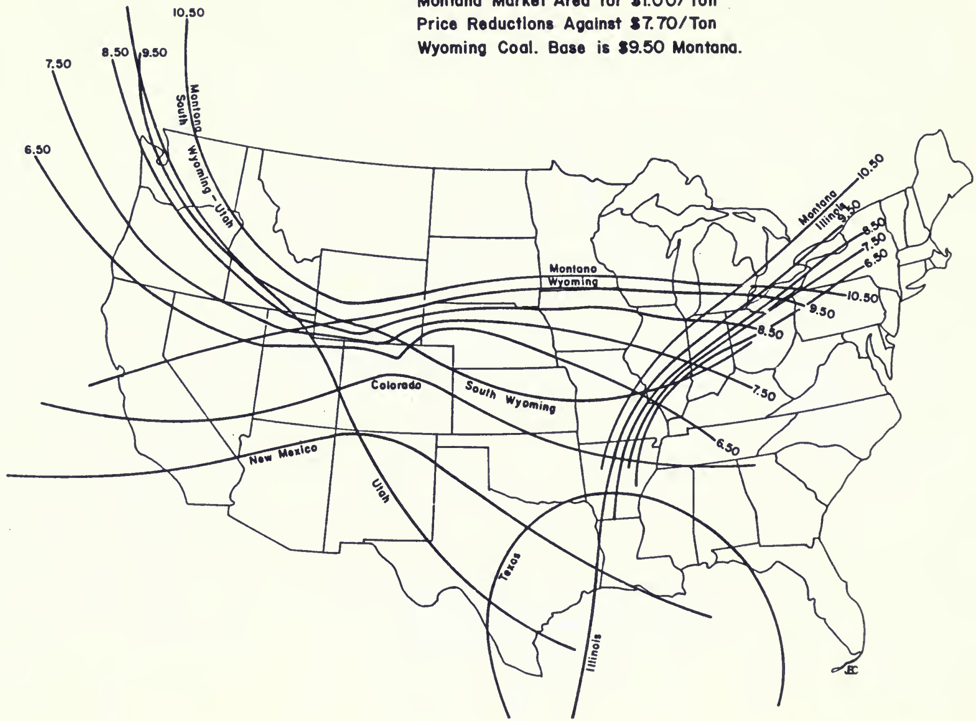
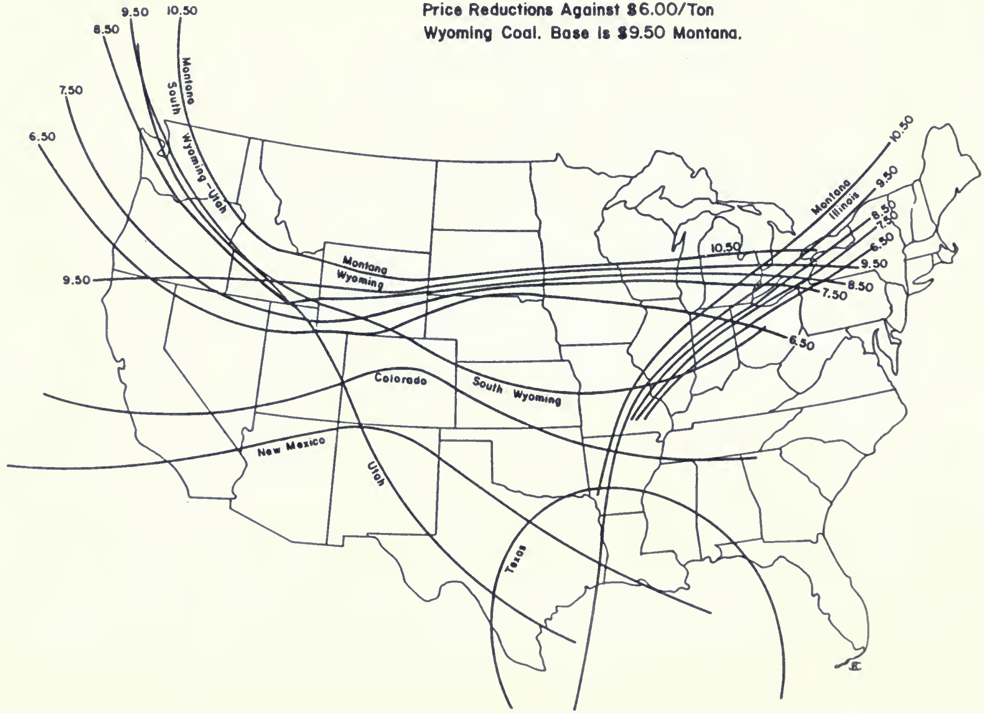


Figure C-3

Montana Coal Market Area for $1.00/Ton Price Reductions Against $6.00/Ton Wyoming Coal. Base Is $9.50 Montana.



Appendix D. The Decker Market

Developing a coal production forecast for Montana coal is complicated by the fact that there are two somewhat different coals in Montana (as noted previously). The Decker/Spring Creek 9300 to 9600 BTU coal at '83 average prices is not competitive with 8450 BTU Wyoming coal at $6 to $7 a ton. These Montana coals appear to have commanded a substantial price premium in the past. There are several probable reasons for the much higher prices commanded by the high BTU coals. The principle destinations for these coals are Commonwealth Edison and other utility plants in northern Illinois, Indiana and Michigan. These are mostly older plants built in the 60's and 70's that now face sulfur emission regulations of sometimes as low as 1.2 lbs./SO_2 per million BTU. It is possible for these older plants to burn Decker and south Wyoming coal with no scrubbing and still meet the standards. Accordingly they are now paying $55 to $80 a ton delivered for Decker and south Wyoming rather than $30 Illinois coal because the latter is 3% sulfur and would require very high scrubber retrofit costs. These plants, in addition, may have no choice but to burn the higher BTU coals since they were originally designed for bituminous coal. In short, it appears that Decker and south Wyoming may have a captive special market.

Decker appears to have the edge in this market at present. This is supported by the prices reported for July 1984 shipments. For example, delivered prices to Commonwealth Edison's Waukegan plant was 343.8¢/MBTU (or $65.94/ton on 9591 BTU coal) from the Black Butte (Green River area) mine and 281.0¢/MBTU (or $53.82/ton on 9577 BTU/lb. coal) from Decker. However, from the standpoint of new plants which can design for any coal rank, Decker at $20/ton is clearly out of the market against Powder River Wyoming in all locations.

At the very much lower prices for new contracts suggested by <u>Coal Week</u> for 9300 BTU Montana coal of $12/ton, a corresponding price for Decker at 9600 BTU would be about $12.50 or 65¢/MMBTU. By contrast even at $7.70 and 8450 BTU, Wyoming coal is only 46¢/MMBTU. On top of this Wyoming Powder River coal has a 130 mile or so advantage to the south and south-central over Decker, worth another 13¢/MMBTU. This 32¢/MMBTU disadvantage to Decker against Wyoming Powder River is partially overcome by transportation savings due to higher BTU's per ton--around 13¢ at 1000 miles and 20¢ at 1500 miles. The conclusion here is that even at the prices suggested by <u>Coal Week</u>, Decker is not competitive for <u>new plants</u> in the south and south-central states. For large price reductions (up to $3) Decker is similar to 8700 BTU Montana in the south and south-central region and will accordingly be modeled together.

In the north central states of Minnesota, Wisconsin, and Michigan, Decker at $12.50 is not competitive against 8700 BTU Montana at $9.50, for new plants under the RNSPS. This is not contradicted by the fact that the one recent new Decker contract is for the new Belle River plant in Michigan. This plant is the last Michigan plant to come on-line under the old NSPS 1.2 lb. SO_2/MMBTU regulation. As explained earlier (Chapter II), the 8700 BTU Montana coal is priced out of this particular market due to scrubber requirements on this somewhat higher sulfur coal.

It appears that at present Decker is practicing intelligent price discrimination in the particular markets where it has an advantage. If Decker or similar mine locations should find it necessary to go into the RNSPS new plant market to utilize or expand existing capacity, it is not clear how low a price could be sustained. At current prices and rail rates, for new plants coming in under RNSPS, 8700 BTU Montana coal appears to dominate or equal Decker coal in most potential market locations. Accordingly, given price

uncertainty and market dominance, the production forecast and analysis presented in Chapter III is based on 8700 BTU Montana coal.

Decker Type Coal: Montana Resources

The unusual character of Decker/Spring Creek coal compared to the rest of the Powder River Basin raises the question of long and short term market availability and competition. Decker coal is high BTU (9300-9500), low sulfur (.3% to .4%) and average ash and water content compared to most other Montana and Wyoming coals. As such they would appear to be very desirable as replacement, mixing and even new boiler fuels in the Northern Great Plains market area as defined by Duffield and Silverman (1982). New contracts for the Decker-like coal from the Decker or Spring Creek mine, or other potential mining sites, depend upon the reserve base of the sites, as well as mining and delivered costs. It is therefore constructive to look at the resource factors at each current potential mining site in Montana containing Decker-like coal.

The two operating mines in Montana with high BTU coal are the East Decker mine, West Decker Mine (including the North Decker Extension) and the Spring Creek Mine. Table D-1 lists the coal production data for Montana for the last few years.

Both the Decker mines and the Spring Creek are important Montana producers, accounting for 15 mtpy in the year (1981) before the national recession that forced production cutbacks nationwide. The permited reserves and design capacity of the Decker and Spring Creek mines are presented in Table D-2. The reserves include those on both federal and non-federal lands. Production for the first 9 months of 1984 appears up over 1983, reflecting the rebound in the economy, and the ability of utilities to increase electric power production.

Table D-1

Montana Coal Production: 1979-1983

Name of Company	Name of Mine	County & Town	1979	1980	1981	1982	1983
Decker Coal Company	East Decker Mine	Big Horn Co. Decker	5,697,433	5,576,607	6,350,113	4,914,970	5,040,016
Decker Coal Company	West Decker Mine	Big Horn Co. Decker	7.067,374	5,618,695	5,331,626	4,884,920	5,308,799
Knife River Coal Co.	Savage Strip Mine	Richland Co. Savage	305,143	305,578	204,492	171,558	206,543
Long Construction Co.	Rosebud Mine	Rosebud Co. Colstrip	11,725,558	10,401,972	10,352,966	9,424,657	9,544,062
Morrison-Knudsen Co., Inc.	Absaloka Mine	Big Horn Co. Hardin	4,947,608	4,905,262	4,450,296	4,158,578	3,868,844
P & M Coal Company	P M Surface Strip	Musselshell Co. Roundup	11,692	11,169	7,404	15,141	11[illegible]
Peabody Coal Company	Big Sky Mine	Rosebud Co. Colstrip	2,457,633	2,964,359	3,193,570	2,891,428	2,571,881
Spring Creek Coal Co. (NERCO)	Spring Creek Mine	Big Horn Co. Decker		95,634	4,368,865	1,352,181	2,102,606
Storm King Coal Mining Co. (Divide Coal Co. mid-1982)	Storm King Mine	Musselshell Co. Roundup	9,464	8,571	8,165	8,062	5,698
Coal Creek Mining Co.	Coal Creek Mine	Powder River Co. Ashland	29,876	64,398	64,142	16,608	
Beartcoth Coal Co.	Brophy #2 Mine (Underground)	Carbon Co. Red Lodge	715	7,321			
Total Coal Tonnage Production by Year			32,452,496	29,957,586	33,331,658	27,838,301	28,660,284

Source: Dept. of Labor and Industry

Table D-2

Reserves, Design and Production of
High BTU Coal, Montana
(in 900 tons)

Mine	Reserves	Design Capacity (mt/yr)	1983 Prod.	1984 Prod. (to Oct. 1)
East Decker	172,590	6,000	5,040	4,458
West Decker	175,300	7,000	5,309	4,664
North Decker (W. Decker Extension)	57,412	2,400	0	0
Spring Creek	184,000	7,000	2,103	2,442

Source: Montana Dept. State Lands (1984)

For Montana's three (4) operating high BTU mines, available tonnage for new contracts, after subtraction of past production and current contract-life tonnage, is reported in Table D-3.

Table D-3

Uncommitted Reserves at Decker
and Spring Creek Mines
(in 10^6 tons)

Mine Name	Total Reserves	Mined to Date	Total Contracted Tonnage	Reserve Available
East Decker	172.6	20.0 (Est.)	62.0	+ 110.0
West Decker	175.3	74.0 (Est.)		
North Decker	57.4	0	236.3	- 3.6
Sub Total	405.3	94.0	298.3	106.4
Spring Creek	184.0	8.0	80.0 (Est.)	104.0
Total	589.3	102.0	378.3	211.0

Source: MBMG, Contract Data (Green)

Approximately 200 million tons of uncommitted coal remain at Decker and Spring Creek. Mined over a 20 year contract life, each mine site should still be in position to provide 5 million tons per year, or 10 million tons per year total; a substantial increase to current production levels. In both mines, only modest expansion of current design capacity would be needed to mine out all economic coal in 20 years.

Let us now consider Decker-like coals in public and private leases that are not yet developed for mining, and estimate the potential for production should markets develop in the future. Table D-4 provides data on mine lease sites, both federal and non-federal, and estimated minimum in place tonnage of high BTU (+ 9300) coal, as well as the OTA (1982) estimate of 1991 production likelihood and planned capacity. The Montco lease on non-federal land is included because of its recent history, even though most of the coal is below the 9300 BTU cutoff, ranging from 8500 to 9300 BTU per pound.

Table D-4: Estimated Resources of High BTU Coal at Undeveloped Leases in Montana

Federal Lease Mines	1991 Prod.	1991 Cap. (mt)	Est. Resources Base (m.t.)
Cx Ranch (Consol.)	Fav	8.0	(+ 200) 322
Cx Ranch (PKS)	Fav	4.0	(+ 100)
Pearl Mine (Shell)	Unfav	2.0	50-100
Wolf Mine ( )	Unfav	?	50-100
Non-Federal Lease Mines			
Montco	Fav	9.0	> 200
Youngs Creek	Unfav	8.0	235
		31.0	875(Min.)

Source: OTA, 1982, Montco Impact Statement, MBMG

It is important to point out that, although over 1 billion tons of high BTU coal remain for sale in Montana, no new contracts have been signed beyond what is already in place at either of the operating mines or the lease holdings. Although mining costs in the high BTU fields of Montana are not specifically known for undeveloped sites, they are all fairly comparable to the Decker/Spring Creek systems, which in turn are not too different from Colstrip.

In addition, the OTA (1982) survey of mine plans suggested that at least some of this uncommitted high BTU coal might even be in production by 1986, with 8.0 mtpy from Consolidation Coal's Cx Ranch site, 4.0 mtpy from Peter Kiewitt's Cx Ranch site and 2.0 mtpy from the Montco site. Clearly, none of these mine sites will reach the 1986 target, and Consolidation Coal has recently closed its Montana office. OTA also reported that mine developers at the Cx Ranch sites, Montco and Youngs Creek expected tonnage capacity to increase to 29 million tons per year by 1991. Again, this estimate looks highly unlikely, given the state of electric power consumption, utility planning, air pollution control strategies, and the state of the synthetic fuel industry in the U.S.

References

Office of Technology Assessment, 1981, An Assessment of Development and Production Potential of Federal Coal Leases; Congress of the United States, U.S. Government Printing Office, 473 pages.

Western Energy Company, 1983, Proposal to Revise the Present Status of Reclamation Bonding at the Rosebud Mine, Submitted to the Montana Department of State Lands, Helena, Mt., 28 pages.

Duffield, John and Silverman A.J., et. al., 1982, Projections of Coal Demand from the Northern Great Plains Through the Year 2010; Office of Surface Mining, U.S. Department of Interior.

U.S. Bureau of Land Management, 1982, Draft, Fort Union Coal Regional Environmental Impact Statement, U.S. Department of Interior, Montana State Office, Billings, Mt.

Montana Department of State Lands, July 1984, Final Environmental Impact Statement, Montco Mine, Rosebud County, Montana.

Montana Environmental Quality Council, Annual Report, Eighth Edition and Final Status of Natural Resource Legislation in the 48th Legislature, Dec., 1983, 189 pages.

Appendix E. Status of Mine Production in Montana and Wyoming

Thick seams, low sulfur content and shallow overburden all characterize the coals of Montana and Wyoming, and especially the shared Powder River Basin. In the late 1970's, concern about air pollution, especially acid rain, and unit train development brought northern plains coal into the midwest and midsouth markets. Early 1970's projections of high energy and electric utility growth rates, along with the conversion or phase out of oil- and gas-fired electric generation, suggest the very extensive development of Powder River Basin coals. Such forecasts, together with rapid leasing of federal, state and private coal lands in the late 1960's, placed the Powder River Basin in a position poised for rapid coal development in the eighties and nineties, continuing the startup surge of the seventies.

Needless to say, the collapse of the economy in 1981-82, conservation measures, the drop in world and U.S. oil prices and the realization that synthetic fuels from coal is many years away from competitive pricing, have set even the most conservative forecasts for coal development back (or forward in time). It is instructive, however, to review the level of planning in the early eighties in order to anticipate the competitive conditions that will, in part, guide future development of coal deposits.

In addition, the coal development scenarios of the Powder River/Northern Great Plains are in large part influenced by the federal government. As the largest coal owner in the PRB, lease policy, and rental and royalty fees drive competition for lease blocks and development plans. An important consideration is the "due diligence" requirements of federal leases. This requirement obligates the leasee to place resources into production at significant mining rates, and within relatively short time frames. For the

current federal leases, a number do not appear likely to meet the due diligence schedule, and therefore, can loose lease rights (OTA, 1982). Private and state leases generally offer more flexibililty in development schedules.

Table E-1, taken from the OTA (1982) study of coal leasing in the west, shows the number of mines, leases and estimated resource base for federal leases in Montana and Wyoming.

Table E-1: Approved Mine Plans with Federal Coal Leases (mil tons)

Montana	No. Leases	No. Mines	Mine Reserves. (mt)	Federal Mine Reserves (mt)
Powder River	12	5	480	400
Wyoming				
Powder River	24	12	4,500	4,200
Total	36	17	4,980	4,600
S. Wyoming				
Hanna	15	6	200	70
Rock Springs	5	3	400	800
Kemmerer	3	2	130	5

Source: OTA (1982) Table 49

Powder River Basin mines with federal leases are reviewed in Tables E-2 and E-3. Of specific note is the contract data and the leasees' estimate of 1991 production levels. The 1986 mine design capacity nearly exactly matches the 1991 production estimate made by the coal companies. With the recent set back in new coal sales and contract deliveries, it is unlikely that mine capacity expansion will take place on the original schedule.

Table E-2

—Powder River Basin Federal Mine Statistics

Mine name	Lessee[c]	Number of Federal leases	Federal[a] lease reserves (billion tons)	Acreage: Total permitted mine plan acreage	Acreage: Federal lease acreage	First coal shipped	Cumulative production 1976-1979 (million tons)	Production 1979 (million tons)	Remaining[b] mine life
(Montana)									
Rosebud	Western Energy Co.	5	HM	6,198	6,227	1920's	41.3	11.7	40 years
Big Sky	Peabody Coal Co.	1	LM	2,351	4,307	1969	9.3	2.5	38 years
Spring Creek	Spring Creek Coal Co.	1	L	3,016	2,347	1980	0.0	0.0	25 years
West Decker	Decker Coal Co.	4	HM	3,137	4,961	1972	55.7	7.1	21 years
East Decker	Decker Coal Co.	1	L	4,376	9,410	1976	5.9	5.9	27 plus years
Montana totals		12	0.8	19,080	29,252		112	27.2	
(Wyoming)									
Buckskin	Shell Oil Co.	1	LM	1,467	600	1981	0.0	0.0	16 years
Rawhide	Carter Mining Co.	1	L	7,393	5,697	1977	7.2	3.6	28 years
Eagle Butte	AMAX Coal Co.	1	L	4,304	3,520	1978	4.0	3.7	37 years
Wyodak	Wyodak Resources	3	HM	3,240	1,880	1922	6.3	2.4	43 years
Ceballo	Carter Mining Co.	2	L	10,040	5,360	1979	1.4	1.3	44 years
Belle Ayr	AMAX Coal Co.	2	L	6,280	2,401	1973	53.8	15.0	19 years
Rojo Caballos	Mobil Oil Corp.	2	L	5,815	3,959	1983	0.0	0.0	27 years
Cordero	Sunoco Energy Dev. Co.	1	L	6,232	6,560	1976	9.8	3.8	28 years
Coal Creek	Atlantic Richfield Co.	1	L	9,545	5,806	1981	0.0	0.0	35 years
Jacobs Ranch	Kerr-McGee Coal Co.	2	L	4,959	4,352	1978	8.5	4.7	22 years
Black Thunder	Thunder Basin Coal Co.	2	L	7,580	5,884	1977	10.3	6.2	38 years
Dave Johnston	Pacific Power & Light Co	6	LM	14,305	9,882	1958	13.1	3.8	18 years
Wyoming totals		24	4.4	83,140	55,880		112	44.5	
Powder River basin totals:		36	5.3	102,220	84,932		225	71.7	

[a]Non-Federal reserves in logical mining units with these Federal lease reserves will add approximately 0.3 billion tons of recoverable reserves in both Montana and in Wyoming to the above totals (approximately 0.6 billion tons in all would be added to the above Powder River basin lease total).

[b]As reported by the lessees in their mine plans.

[c]See the OTA Working Lease List, app. B, for a listing of both parent companies and subsidiaries.

Key to reserve ratings:
- S = small reserves (zero to 30 million tons)
- LM = low to medium reserves (30 million to 100 million tons)
- HM = high to medium reserves (100 million to 180 million tons)
- H = high reserves (over 180 million tons)

SOURCE: Office of Technology Assessment.

Table E-3

—Powder River Basin Federal Mine Production, Capacity, and Contracts
(millions of tons per year)

Mine name	1980 mine design capacity	Production 1980	1986 mine design capacity	OTA estimated production-1986 demand scenario: H	OTA estimated production-1986 demand scenario: L	Contracts for 1986	Lessees' estimates of production-1986	1991 mine design capacity	OTA estimated production-1991 demand scenario: H	OTA estimated production-1991 demand scenario: L	Contracts for 1991	Lessees' estimates of production-1991
Montana												
Rosebud	14.2	10.4	19.8	19.5	16.3	19.4	19.4	19.8	19.8	17.5	19.8	19.8
Big Sky	4.8	3.0	4.8	4.8	3.9	4.8	4.8	4.6	4.8	4.1	4.8	4.8
Spring Creek	0.2	0.1	10.0	7.8	5.9	7.0	7.8	10	9.2	8.2	7.0	10.1
West Decker	10.4	5.8	10.4	7.5	6.8	8.7	8.0	10.4	9.4	5.9	8.7	6.0
East Decker	6.7	5.6	6.7	6.8	5.0	6.7	6.8	6.7	6.9	5.9	6.7	6.6
Montana totals	36	24.7	52	46	37	44	46	52	50	40	45	49
Wyoming												
Buckskin	0	0	6.2	6.2	5.2	6.2	6.2	6.2	6.2	5.5	6.2	6.2
Rawhide and Ceballo	12 + 4	6.4	24 + 12	20.4	13.8	16.0	31.0	24 + 12	30.7	14.2	16.0	36.0
Eagle Butte and Belle Ayr	14 + 21	24.5	25 + 11	33.7	27.8	33.0	33.0	25 + 11[a]	35.2	29.2	33.0	32.0
Wyodak	3	2.6	5	3.4	2.5	3.0	3.0	5	4.9	4.0	4.5	4.5
Rojo Caballos	0	0	9	4.5	2.7	2.6	9.0	15	12.5	5.0	5.8	15.0
Cordero	24	6.5	24	13.9	9.3	11.0	16.0	24	20.5	9.7	11.0	24.0
Coal Creek	0	0	12	8.4	4.0	4.8	9.8	12	10.1	4.2	4.8	12
Jacobs Ranch	16	8.2	16	13.6	11.1	13.2	15.6	18	15.3	11.7	13.2	15.6
Black Thunder	14	10.5	20.5	17.4	13.9	16.5	17.0	20.5	19.4	14.6	16.5	20.5
Dave Johnston	3.8	3.8	3.8	3.7	3.1	3.7	3.7	3.6	3.8	3.3	3.7	3.7
Wyoming totals	112	62.5	169	123	93	110	144	175	159	101	115	170
Powder River basin totals	148	87.2	220	169	130	154	191	226	209	141	159	219

[a]This capacity estimate based on remaining reserves.

SOURCE: Office of Technology Assessment.

Leases with approved mine plans (Table E-4) in Montana and Wyoming provide a potential production for the two states in 1986 and 1991 of 219 m.t. and 248 m.t. respectively. Montana potential production will closely follow the contract levels for the year 1986 and 1991; however, the Wyoming potential is far in excess of current contract commitments for 1991.

Table E-4: Approved Mine Plans with Federal Coal Leases (mil tons)

Montana:	1979 Prod.	1984 Prod.	1986 Pot.	1991 Pot.
Powder River Basin	27.1	33.0	46.0	49.0
Fort Union Basin	0.3	0.3	0.3	0.3
Sub Total	27.4	33.3	46.3	49.3
Wyoming:				
Powder River	45	120	144	170
Hanna	11	?	10	8
Rock Springs	7	?	13	15
Keinmerer	5	5	6	6
Sub Total	68	125+	173	199
Grand Total	95.4	158.3+	219.3	248.3

Note: Pending plans if not withdrawn range from 0-9.0 m.t. in MT (1986-91) and 10-70. m.t. in WY (1986-91)

Source: OTA, 1982, Table 47

In addition to mines on federal lands, private ownership and state leases provide additional opportunity for production (Table E-5). Although plans for capacity expansion are almost always predicated upon coal sales, planning often preceeds contract signatures and cutbacks are easier to implement than rapid expansion. Therefore, it is likely that Montana capacity will not reach

50 million tons in 1991 under current conditions. Wyoming expansion plans are mitigated by the enormous mine capacity already in place, and significant expansion of non-federal mines seems unlikely given the development requirements on federal leases. The incentive for federal lease holders is to cut costs and profits in order to put properties into production wherever possible.

Table E-5: Major Non-Federal Mines in the Powder River Basin (mt/yr)

	1986		1991	
	Capacity	Contracts	Capacity	Contracts
Montana				
Absaloka	10.5	5.1	10.5	5.1
Montco	2.0	0	9.0	0
Youngs Creek	--	--	8.0	0
Bull Mts.	0.5	0	2.0	0
Sub Total	13.0	5.1	29.5	5.1
Wyoming				
Bighorn	3.0	3.0	3.0	3.0
[a]Wymo	4.0	2.0	4.0	2.0
Clovis Point	5.0	0	5.0	0
Sub Total	12.0	5.0	12.0	5.0
Grand Total	25.0	10.1	41.5	10.1

a = utility captive

Source: OTA, 1982

Appendix F. Decision Theory Analysis of Severance Tax Cut Impacts on Expiring Montana Contracts

This appendix provides a preliminary analysis of the impacts of severance tax cuts on Montana coal contract renewals. The overall effect of a Montana tax cut will depend on a number of factors, such as the electric growth rate. For expiring contracts the key uncertainty is the level of supply prices for competing coals, particularly Wyoming. A decision theory model which takes account of the risk associated with alternative Wyoming prices is developed below, for application to the expiring contract issue. A similar analysis for all categories of potential demand (new plants, acid rain plants) would be appropriate but is beyond the scope of this project.

Montana coal contracts that are known to be expiring by 1995 are summarized in Table F-1. The contracts total around 14.5 mtpy (based on an average of contract minimums and maximums). Actual 1983 contract deliveries totaled 12.6 mtpy to these burn sites. By 1995 expiring contracts will be about one-third of projected 1995 Montana production (at 46 mtpy). All contracts expiring to 1995 are for the 8700 BTU Montana producers. Westmoreland and Peabody production is currently 100% on contracts that will expire by 1995. Western Energy is somewhat less exposed with 58% of today's production due to contracts to expire by 1995 and dropping to around 40% by 1988. In short, expiring contracts are a significant share of current and forecast production, particularly for Westmoreland and Peabody.

Table F-2 provides an estimate of a breakeven Wyoming minemouth (FOB) price that would just match Montana FOB of either 9.50 $/ton or 10.50 $/ton (both cases presented). The estimates are based on differences in transportation cost. For example the Corette plant in Billings is only 110 miles further from Gillette than from Colstrip. Using an incremental cost

Table F-1

Summary of Expiring Contracts by Burn Site

State	Utility	Burn Site	Quantity (mtpy)	Expiration Date
Montana	MPCo	Corette	.6	'90
	Subtotal		(.6)	
Minnesota	NSP	Sherburne	4.5	'93-'95
		Minneapolis Area	2.3	'93-'95
	MPL	Clay Boswell	3.6	'93
		Laskin (Aurora)	.2	'93
	Subtotal		(10.6)	
Wisconsin	WPL	Nelson Dewey	.2	'93
		Columbia	2.0	'94
	DP	Alma	.2	'93
		Genoa	.3	'93
	Subtotal		(2.7)	
Michigan	UPG	Presque Isle	.6	'91-'95
	Subtotal		(.6)	
Total			14.5	

of .017 \$/ton-mile this is a \$1.87 transportation difference that Wyoming coal would have to make up with lower FOB mine price to equal the delivered price of Montana coal. For example, if Colstrip FOB is 9.50, Wyoming "breakeven" FOB is 9.50 less 1.87 or 7.63 as shown in Table F-2. All other estimates are derived in a similar manner, except where actual rail tariffs were available. In general foremost Minnesota, Wisconsin, and Michigan burn sites, Montana has a rail advantage of 200 to 300 miles or \$3.50 to \$5.00 per ton. We have ignored here any boiler or scrubber-related costs that may vary due to coal characteristics.

Table F-2

Breakeven Wyoming Prices by Burn Site for Existing Montana Contracts

Burn Site			Montana FOB	
			9.50	10.50
State	Utility	Plant	Wyoming Break Even Price*	
Montana	MPCo	Corette	7.63	8.63
Minnesota	MPL	Clay Boswell	4.91	5.59
	NSP	City Plants	5.67	6.67
		Sherco	4.94	5.94
Wisconsin	WPL	Nelson Dewey	7.29	8.29
		Columbia	3.61	4.61
	DP	Alma	4.81	5.81
		Genoa	4.21	5.21
Michigan	UPG	Presque Isle	4.57	5.57

Source: Based on actual difference in rail tariffs where known (eg., Columbia) and estimated using .017 $/ton-mile and mileage difference (tariff or estimated) where not known. Breakeven is not corrected for BTU content difference (ie, assume all coal 8700 BTU/lb).

Given an actual distribution for Wyoming contract prices, it is possible to estimate the probability that Wyoming will secure an expiring Montana contract with a bid less than or equal to the "breakeven" price by burn site. The distribution used here is the lower half (10 observations) of the successful Wyoming bids (contracts) summarized in Figure 7 of Chapter III. The mean of this distribution is 7.33 $/ton, with a range of $4.75 to $8.72 and a sample standard deviation of 1.437. This mean is below but close to the mean for new Wyoming contracts suggested to us by the Wyoming Geological Survey at 7.70 $/ton and is accordingly perhaps a little pessimistic (favoring Wyoming) for current conditions. More importantly, it may be very pessimistic for the time when contracts are actually renewed. The actual mean for all Wyoming contracts is 9.77 $/ton. It is obviously difficult to predict the

aggregate coal market in 1990 to 1995. The following results may well be conservative since they are based on "soft" market conditions.

For purposes of illustration and simplicity, it is assumed that Wyoming prices are normally distributed. Based on this assumption and the breakeven prices in Table F-2, the probability of Wyoming successfully securing Montana's expiring contracts is summarized by burn site in Table F-3. For example, at Corette, we estimate the probability of a successful Wyoming bid at 82% if the Montana FOB is \$10.50, 58% at 9.50 and 31% at 8.50. The probability of a Montana contract renewal here is of course "one" minus the Wyoming probability, so that as the Montana FOB (bid) price declines from 10.50 to 9.50 to 8.50 the likelihood of getting the contract increases from (1.00 minus .82, etc) 18% to 42% to 69%.

It should be noted that we have of course ignored the captive mine issue with respect to Corette. Similarly we ignore the presence of other competitors. Almost certainly Nelson Dewey, Alma, and Genoa (totaling only .7 mtpy) will be captured by low sulfur eastern coals. These two issues tend to cancel in the results; however, these burn sites are retained in Table F-3 to broaden the illustration.

Price difference in Table F-3 for Montana FOB can of course be interpreted as price reductions due to severance tax changes from a given base price (eg. Montana FOB of \$9.50 or \$10.50). For policy analysis of this decision under risk, an appropriate criteria is the expected value criteria:

$$\text{Expected Value (of Policy X)} = \sum_j \pi_j M(X)_j$$

Where π_j are the probabilities of the relevant "state of the world" (Wyoming or Montana gets the contract) over "j" burn sites,

$M(X)_j$ are the physical or monetary outcomes (eg. Montana severance tax revenue, or coal production levels) associated with policy "X" (eg. severance tax reduction, no tax reduction, etc.) at burn site j.

Table F-3

Probability of a Successful Wyoming Bid on Expiring Montana Contracts by Burn Site

Burn Site	Quantity (mtpy)	Montana FOB Price ($/ton) 10.50	9.50	8.50
Corette	.6	.82	.58	.31
Clay Boswell	3.6	.11	.05	.01
NSP City Plants	2.3	.31	.12	.03
Sherco	4.5	.17	.05	.01
Nelson Dewey	.2	.75	.49	.24
Columbia	2.0	.03	.01	.01
Alma	.2	.14	.04	.01
Genoa	.3	.07	.02	.01
Presque Isle	.6	.11	.03	.01

Source: Based on breakeven prices (Table F-2) and against a Wyoming contract (successful bids) price distribution with a mean of 7.33 $/ton and a sample standard deviation of 1.437 (assumed normal distribution).

In short, the preceding specification takes account of the fact that changing prices through severance tax reductions does not guarantee results but rather affects the probability of (here) retaining contracts. As can be seen in Table F-3, at most sites we are relatively sure of retaining contracts and the effect of $1.00 per ton (equivalent to 50% tax reduction at $9.50 Montana FOB) price reductions is small. For example at the largest contract, Sherco units 1 and 2 near Minneapolis, at $9.50 Montana FOB we estimate a 5% chance of a Wyoming contract. The tax reduction to $8.50 reduces this to 1%.

Using this methodology, the probable contract renewals (on a maximum of 14.3 mt, as the Laskin unit is excluded) is 11.6 mtpy at $10.50 Montana FOB, 13.1 mtpy at $9.50 and 13.9 mtpy at $8.50. As developed in Table F-4, the probable tax revenue with no change in tax rate is around $25 million per year. The tax revenue with a 50% tax cut is down considerably per ton and generates only a small probable increase in tonnage (1.5 mtpy at a base price of $10.50 and .8 mtpy at $9.50). As a result, the conclusion is that a large tax revenue loss is likely assuming Montana producers are at $10.50 or $9.50 FOB of around $13 million/year.

Table F-4

Expected Value of Annual Severance Tax Revenues for Changes in Tax Rate on Contracts Expiring by 1995

	Cases		
	Montana FOB Price ($/ton)		
Category	10.50	9.50	8.50
Probable quantity of contract renewals (mtpy)	11.6	13.1	13.9
Tax revenue, no tax cut (million $)	25.7	26.2	24.9
Tax revenue, 50% cut (million $) (by initial base price)	13.1	12.5	
Probable net loss to tax cut	12.6	13.7	

Source: Based on the probabilities of contract renewal provided in Table F-5 and assuming Wyoming is the only competitor. (In fact Genoa, Alma, and Nelson Dewey will all go to Eastern low sulfur coal for a net contract loss of .7 mtpy and offsetting this Corette will remain captive at .6 mtpy).

These results are sensitive of course to the assumed bid distribution. Alternatively, if we were certain that Wyoming producers would bid, say $6/ton for an appropriate coal, we could also use the breakeven price Table F-2 to

calculate the consequences of a "certainty" case. These results are summarized in Table F-5. As is apparent contract renewals are not sensitive to a Wyoming price range of \$5 to \$8/ton except at \$10.50 Montana FOB. If Montana coal producers cannot offer an FOB below 10.50 \$/ton in soft market conditions they are in trouble on contract renewals against \$5/ton Wyoming. If this extreme low Wyoming bid and high Montana bid occurred at every burn site between 1990 and 1995 we would renew only 2 mtpy out of 14.3. A tax cut here would have a positive impact by getting us to 11.5 mtpy for a net tax revenue gain of \$7.1 million. All other cases show a net loss of \$10.8 million to \$16.6 million. The odds of the \$10.50 Montana and \$5.00 Wyoming case consistantly occurring are probably quite low. In fact the "probable" case is what has been outlined in Tables F-3 and F-4. Clearly the risk/benefit result is sensitive to the assumed price distribution. We will know a lot more about this as the mid-1990's approach. On a simple tax revenue loss basis it would appear that the "no loose" solution here is to defer possible tax reductions to the future.

Table F-5

Certainty Case Summary of Annual Tax Revenue Loss on Montana Coal Contracts Expiring by 1995

Montana FOB Price	Wyoming FOB Mine Price ($/ton) 5.00	6.00	7.00	8.00
	A. Quantity of Renewed Montana Contracts (mtpy)			
10.50	2.0	11.5	13.8	13.8
9.50	11.5	13.8	13.8	14.3
8.50	13.5	13.5	14.3	14.3
	B. Tax Revenue with No Tax Cut (million $/yr)			
10.50	4.4	25.4	30.4	30.4
9.50	23.0	27.6	27.6	28.6
8.50	24.2	24.2	25.6	25.6
	C. Tax Revenue with 50% Cut (million $/yr)			
cut to 9.50	11.5	13.8	13.8	14.3
cut to 8.50	12.2	12.2	12.9	12.9
	D. Net Loss Due to Tax Cut (million $/yr)			
Base 10.50	(7.1)	11.6	16.6	16.1
Base 9.50	10.8	15.4	14.7	15.7